DOD-IR-1

Please provide a copy of all of the data requests HECO has received from other parties to date.

HECO Response:

Hard copies of the Consumer Advocate's ("CA") information request submissions one to ten to Hawaiian Electric Company ("HECO") were sent by express mail to the Department of Defense ("DOD") on March 16, 2005. Electronic files for the CA's IR submissions one to 11 to HECO were emailed to the DOD on March 18, 2005. Electronic files for the CA's IR submissions 12 and 13 to HECO were emailed to the DOD on March 22, 2005 and March 28, 2005, respectively. HECO will continue to provide the DOD via email the CA's IR submissions to HECO.

DOD-IR-2

Please provide HECO's responses to all Consumer Advocate data requests issued to date.

<u>HECO Response:</u>

HECO's responses to the Consumer Advocate ("CA") data requests were provided to the DOD by express mail on the following dates: 1) March 16, 2005, 2) March 17, 2005, 3) March 18, 2005, 4) March 22, 2005, and 5) March 24, 2005. HECO has provided the DOD with copies of all of its responses to the CA's information requests that were filed with the CA as of March 24, 2005. HECO will provide the DOD copies of its responses to the CA's information requests and mail them to the DOD via express mail delivery on the same day the responses are filed with the CA.

DOD-IR-3

Please provide a copy of all discovery requests issued by other parties from this point forward, and also provide HECO's responses to such discovery to DOD simultaneously with when HECO provides such responses to the issuing party.

HECO Response:

HECO will email the DOD all discovery requests issued by the Consumer Advocate when it [illegible]

receives the electronic file from the Consumer Advocate. HECO will provide the DOD with [illegible]

DOD-IR-4

To the extent not filed by HECO as part of its filing or in the response to DOD-2, please provide all Excel files and supporting workpapers for HECO witness testimony T-2 through T-10, T-13 through T-22, and their exhibits.

HECO Response:

The electronic files were provided to the DOD by express mail on March 16, 2005.

DOD-IR-5

Please provide 2 copies of the same 2 CDs containing HECO's work papers and 1999-2003 recorded and 2004-2005 budgeted data for labor and nonlabor costs that HECO provided to the CA as described in HECO's letter to the CA dated December 6, 2004.

<u>HECO Response:</u>

The two CDs will be provided to the DOD under separate transmittal.

DOD/HECO-IR-2-1

Please provide a listing of the following adjustment factors, including all filings with the Commission, by month, for the period January 2003 through December 2004. The adjustments should correspond to the rates applied to the monthly customer bills for the requested period.

a. AES Rate Adjustment pursuant to HECO-105, page 5.

b. Energy Cost Adjustment as set forth in HECO-105, pages 30 and 31.

c. Integrated Resource Planning Cost Recovery Provision as set forth in HECO-105, Pages 40 and 41.

HECO Response:

a. See pages 2-3 of this response for AES Rate Adjustment, labeled as (a) and pages 4-11 for copies of transmittal letters. Note: AES Rate Adjustments commenced on July 31, 2003.

b. See pages 2-3 of this response for Energy Cost Adjustment, labeled as (b) and pages 12-36 for copies of transmittal letters.

c. See pages 2-3 of this response for Integrated Resource Planning Cost Recovery Provision, labeled as (c) and pages 37-45 for copies of transmittal letters.

ATTACHMENT
6

Hawaiian Electric Company, Inc.

FUEL OIL DATA

		GENERATION CENTS / MBTU		PURCHASED CENTS / KWH		(b) ECAF CENTS / KWH	RESIDENTIAL BILL ($)	
Effective Date	Efficiency Factor	Base Price	Comp. Price	Base Price	Comp. Price	Resid & Comm'l	@ 700 kWh	@ 600 kWh
PHASE II PERM RATES EFF 1/1/97 (SUPERCEDES PHASE I RATE STRUCTURE EFF 1/1/96)								
RESIDENTIAL DSM ADJUSTMENT of 0.1885 CENTS/KWH EFF 4/1/02 - 3/31/03								
COMMERCIAL DSM ADJUSTMENT OF 0.2326 CENTS/KWH EFF 4/1/02 - 3/31/03								
(c) ***IRP COST RECOVERY ADJUSTMENT OF 0.00% EFFECTIVE 7/1/02 - 4/30/03***								
JAN 1, '03	0.01117	287.83	528.78	3.005	4.170	2.286	103.39	89.62
FEB 1, '03	0.01117	287.83	547.90	3.005	4.182	2.421	104.34	90.43
MAR 1, '03	0.01117	287.83	575.24	3.005	4.111	2.747	106.62	92.38
RESIDENTIAL DSM ADJUSTMENT of 0.2271 CENTS/KWH EFF 4/1/03 - 4/30/04								
COMMERCIAL DSM ADJUSTMENT OF 0.2303 CENTS/KWH EFF 4/1/03 - 4/30/04								
APR 1, '03	0.01117	287.83	589.00	3.005	4.295	2.855	107.65	93.26
(c) ***IRP COST RECOVERY ADJUSTMENT OF 0.303% EFFECTIVE 5/1/03 - 5/31/03***								
MAY 1, '03	0.01117	287.83	596.95	3.005	4.485	2.918	108.35	93.87
(c) ***IRP COST RECOVERY ADJUSTMENT OF 0.00% EFFECTIVE 6/1/03 - 5/31/04***								
JUNE 1, '03	0.01117	287.83	572.42	3.005	4.450	2.734	106.80	92.53
JULY 1, '03	0.01117	287.83	546.75	3.005	3.996	2.330	103.97	90.11
(a) ***AES CAPACITY RATE ADJUSTMENT OF -0.561% EFFECTIVE 7/31/03 - 12/31/03***								
AUG 1, '03	0.01117	287.83	538.82	3.005	4.043	2.240	102.86	89.15
SEP 1, '03	0.01117	287.83	530.97	3.005	3.928	2.130	102.09	88.49
OCT 1, '03	0.01117	287.83	525.89	3.005	3.841	2.041	101.47	87.96

ADJUSTMENT TO AES RATE ADJUSTMENT OF 0.004% EFFECTIVE 11/01/03 - 1/31/04

NOV 1, '03	0.01117	287.83	512.75	3.005	3.954	2.048	101.52	88.00
DEC 1, '03	0.01117	287.83	529.55	3.005	3.981	2.175	102.41	88.76

(a) ***AES CAPACITY RATE ADJUSTMENT OF -0.406% EFFECTIVE 1/1/04***

JAN 1, '04	0.01117	287.83	565.03	3.005	4.252	2.572	105.31	91.26

ADJUSTMENT TO AES RATE ADJUSTMENT OF -0.005% EFFECTIVE 2/01/04 - 4/30/04

FEB 1, '04	0.01117	287.83	578.41	3.005	4.154	2.599	105.50	91.42
MAR 1, '04	0.01117	287.83	557.13	3.005	4.583	2.726	106.39	92.19
APR 1, '04	0.01117	287.83	567.65	3.005	4.187	2.698	106.20	92.02

RESIDENTIAL DSM ADJUSTMENT of 0.2740 CENTS/KWH EFF 5/1/04
COMMERCIAL DSM ADJUSTMENT OF 0.2379 CENTS/KWH EFF 5/1/04
ADJUSTMENT TO AES RATE ADJUSTMENT OF -0.023% EFFECTIVE 5/01/04 - 7/31/04

MAY 1, '04	0.01117	287.83	595.81	3.005	4.166	2.892	107.86	93.44

(c) ***IRP COST RECOVERY ADJUSTMENT OF 0.696% EFFECTIVE 6/1/04 - 6/30/04***

JUN 1, '04	0.01117	287.83	578.98	3.005	4.453	2.750	107.47	93.11

(c) ***IRP COST RECOVERY ADJUSTMENT OF 0.00% EFFECTIVE 7/1/04***

JUL 1, '04	0.01117	287.83	595.98	3.005	4.365	2.811	107.30	92.96

ADJUSTMENT TO AES RATE ADJUSTMENT OF -0.007% EFFECTIVE 8/01/04 - 10/31/04

AUG 1, '04	0.01117	287.83	601.51	3.005	4.469	3.000	108.63	94.10
SEP 1, '04	0.01117	287.83	624.79	3.005	5.058	3.448	111.77	96.79
OCT 1, '04	0.01117	287.83	693.04	3.005	4.944	3.925	115.11	99.65

ADJUSTMENT TO AES RATE ADJUSTMENT OF 0.024% EFFECTIVE 11/01/04 - 1/31/05

NOV 1, '04	0.01117	287.83	724.09	3.005	5.137	4.382	118.33	102.42
DEC 1, '04	0.01117	287.83	781.65	3.005	4.655	4.575	119.69	103.58

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

July 30, 2003

2003 JUL 30 P 4: 12

PUBLIC UTILITIES COMMISSION

FILED

William A. Bonnet
Vice President
Government and Community Affairs

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building
465 South King Street, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 03-0126
<u>Amendment No. 2 to PPA with AES Hawaii</u>

This is to inform the Commission that AES Hawaii completed its refinancing on July 30, 2003. Pursuant to Order No. 20292, issued on July 1, 2003 and Order No. 20310 issued on July 9, 2003, which authorized HECO to put the Rate Adjustment into effect on short notice, attached is the Rate Adjustment tariff sheet[1], index page and supporting workpapers. As shown on attached page 5, a bill for a residential customer using 600 kwh will be reduced by approximately 42 cents per month.

Sincerely,

William A. Bonnet

Attachment

cc: Division of Consumer Advocacy

[1] The tariff sheet has been modified from the tariff sheet provided in Exhibit B to include Schedules PS, PP and PT in place of Schedule P. Schedules PS, PP and PT replaced Schedule P in Docket No. 00-0042.

SHEET NO. 50.1
Effective July 31, 2003

RATE ADJUSTMENT

Supplement To

Schedule R - Residential Service
Schedule E - Electric Service For Employees
Schedule G - General Service Non-Demand
Schedule J - General Service Demand
Schedule H - Commercial Cooking, Heating, Air Conditioning, and Refrigeration Service
Schedule PS - Large Power Secondary Voltage Service
Schedule PP - Large Power Primary Voltage Service
Schedule PT - Large Power Transmission Voltage Service
Schedule F - Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U - Time of Use Service

All terms and provisions of Schedules "R", "E", "G", "J", "H", "P", "F", and "U", are applicable except that the total base revenues for the billing period shall be decreased by the Rate Adjustment of 0.5610% approved by the Public Utilities Commission. The total base revenues for each billing period includes revenues from base rates, and base rate adjustments, and excluding the Energy Cost Adjustment Clause, the Integrated Resource Planning Cost Recovery Provision, and other non-base rate adjustments.

Rate Adjustment:...................... -0.561 percent

The Rate Adjustment is based on passing through to customers the estimated reduction in capacity payments to AES Hawaii and related revenue taxes totaling $3,187,140 annually pursuant to Amendment No. 2 to the Purchase Power Agreement between AES Hawaii and HECO. The percentage is based on the forecast base revenues for the year. The percentage will be adjusted annually effective January 1 of each year to reflect a revised forecast of base revenues for the year.

RECONCILIATION ADJUSTMENT:

In order to reconcile any differences that may occur between the amount passed through to customers and the estimated reduction in the

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

October 31, 2003

FILED
2003 OCT 31 P 4:08
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: <u>AES Hawaii, Inc. Rate Adjustment Reconciliation</u>

In accordance with Decision and Order No. 20292 in Docket No. 03-0126 of Hawaiian Electric Company, Inc.'s Rate Sheet No. 50.1, the AES Hawaii, Inc. Rate Adjustment Reconciliation Adjustment for November and December of 2003 and January of 2004 is 0.004 percent applied to the total base charges. This is based on an over-return of $7,027.93 of the AES Hawaii, Inc. Rate Adjustment for the period from July 31 through October 2003.

The AES Reconciliation Adjustment applied to the base AES Rate Adjustment of -0.561 percent, which went into effect July 31, 2003, results in a combined factor of -0.557 percent on total base charges for the AES Hawaii, Inc. Rate Adjustment for November 2003 through January 2004.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

SF File (original)

Hawaiian Electric Company • PO Box 2750 • Honolulu, HI 96840-0001

December 31, 2003

FILED
2003 DEC 31 A 10:08
PUBLIC UTILITY COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building
465 South King Street, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 03-0126
Amendment No. 2 to PPA with AES Hawaii

Attached is the updated Rate Adjustment for Hawaiian Electric Company, Inc., which is proposed to become effective January 1, 2004 through December 1, 2004 (See Attachment 1.) The Rate Adjustment is based on the reduction in capacity payments to AES Hawaii refunded to customers and totals $3,187,140 ($2,904,000[1] plus related revenue taxes) pursuant to Amendment No. 2 to the Purchase Power Agreement between AES Hawaii and HECO. The updated Rate Adjustment tariff sheet includes Schedule TOU-R.

Also attached (as Attachment 2) are copies of the currently effective tariff Sheet Nos. 50 and 50.1. Workpapers showing the derivation of the updated Rate Adjustment of -0.406% are attached as Attachment 3. An estimate of the impact of the updated Rate Adjustment on residential customers using 600 kwh per month is shown in Attachment 4.

Sincerely,

Attachments

cc: Division of Consumer Advocacy

1 The reduction in capacity payments to AES Hawaii results from completion of its refinancing on July 30, 2003. The Commission approved HECO's pass through of the capacity payment reduction to customers in Order No. 20292 (July 1, 2003) and Order No. 20310 (July 9, 2003).

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

January 30, 2004

2004 JAN 30 P 4: 10

FILED

PUBLIC UTILITY COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: AES Hawaii, Inc. Rate Adjustment Reconciliation

In accordance with Decision and Order No. 20292 in Docket No. 03-0126 of Hawaiian Electric Company, Inc.'s Rate Sheet No. 50.1, the AES Hawaii, Inc. Rate Adjustment Reconciliation Adjustment for February through April 2004 is -0.005 percent applied to the total base charges. This is based on an under-return of $8,943.19 of the AES Hawaii, Inc. Rate Adjustment for the period from October 2003 through January 2004.

The AES Reconciliation Adjustment applied to the base AES Rate Adjustment of -0.406 percent, which went into effect January 1, 2004, results in a combined factor of -0.411 percent on total base charges for the AES Hawaii, Inc. Rate Adjustment for February through April 2004.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

April 30, 2004

FILED
2004 APR 30 A 10:59
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: AES Hawaii, Inc. Rate Adjustment Reconciliation

In accordance with Decision and Order No. 20292 in Docket No. 03-0126 of Hawaiian Electric Company, Inc.'s Rate Sheet No. 50.1, the AES Hawaii, Inc. Rate Adjustment Reconciliation Adjustment for May through July 2004 is -0.023 percent applied to the total base charges. This is based on an under-return of $41,743.84 of the AES Hawaii, Inc. Rate Adjustment for the period from January through March 2004.

The AES Reconciliation Adjustment applied to the base AES

Rate Adjustment of -0.406 percent, which went into effect January 1, 2004, results in a combined factor of -0.429 percent on total base charges for the AES Hawaii, Inc. Rate Adjustment for May through July 2004.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

July 30, 2004

FILED
2004 JUL 30 P 3: 24
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: AES Hawaii, Inc. Rate Adjustment Reconciliation

In accordance with Decision and Order No. 20292 in Docket No. 03-0126 of Hawaiian Electric Company, Inc.'s Rate Sheet No. 50.1, the AES Hawaii, Inc. Rate Adjustment Reconciliation Adjustment for August through October 2004 is -0.007 percent applied to the total base charges. This is based on an under-return of $12,452.01 of the AES Hawaii, Inc. Rate Adjustment for the period from April through June 2004.

The AES Reconciliation Adjustment applied to the base AES Rate Adjustment of -0.406 percent, which went into effect January 1, 2004, results in a combined factor of -0.413 percent on total base charges for the AES Hawaii, Inc. Rate Adjustment for August through October 2004.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

October 29, 2004

FILED
Oct 29 3 48 PM '04
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: AES Hawaii, Inc. Rate Adjustment Reconciliation

In accordance with Decision and Order No. 20292 in Docket No. 03-0126 of Hawaiian Electric Company, Inc.'s Rate Sheet No. 50.1, the AES Hawaii, Inc. Rate Adjustment Reconciliation Adjustment for November, December 2004 and January 2005 is 0.024 percent applied to the total base charges. This is based on an over-return of $43,027.44 of the AES Hawaii, Inc. Rate Adjustment for the period from July through September 2004.

The AES Reconciliation Adjustment applied to the base AES Rate Adjustment of -0.406 percent, which went into effect January 1, 2004, results in a combined factor of -0.382 percent on total base charges for the AES Hawaii, Inc. Rate Adjustment for November, December 2004 and January 2005.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

FILED
DEC 31 10 40 AM '02
PUBLIC UTILITIES COMMISSION

December 31, 2002

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for January 2003 is 2.286 cents per kilowatthour, an increase of 0.118 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $89.62, $0.71 more than the previous month.

The Company's fuel composite cost of generation decreased 7.06 cents per million BTU to 528.78 cents per million BTU. The composite cost of purchased energy increased 0.344 cents per kilowatthour to 4.170 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning January 1, 2003.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

January 31, 2003

2003 JAN 31 P 3:48
PUBLIC UTILITIES COMMISSION
FILED

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for February 2003 is 2.421 cents per kilowatthour, an increase of 0.135 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $90.43, $0.81 more than the previous month.

The Company's fuel composite cost of generation increased 19.12 cents per million BTU to 547.90 cents per million BTU. The composite cost of purchased energy increased 0.012 cents per kilowatthour to 4.182 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning February 1, 2003.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

FILED

2003 FEB 28 P 3:37

PUBLIC UTILITIES COMMISSION

February 28, 2003

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for March 2003 is 2.747 cents per kilowatthour, an increase of 0.326 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $92.38, $1.95 more than the previous month.

The Company's fuel composite cost of generation increased 27.34 cents per million BTU to 575.24 cents per million BTU. The composite cost of purchased energy decreased 0.071 cents per kilowatthour to 4.111 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning March 1, 2003.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

March 31, 2003

FILED
MAR 31 3 44 PM '03
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for April 2003 is 2.855 cents per kilowatthour, an increase of 0.108 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $93.26, $0.88 more than the previous month.

The Company's fuel composite cost of generation increased 13.76 cents per million BTU to 589.00 cents per million BTU. The composite cost of purchased energy increased 0.184 cents per kilowatthour to 4.295 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning April 1, 2003.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

FILED

APR 30 3 49 PM '03

PUBLIC UTILITIES COMMISSION

April 30, 2003

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for May 2003 is 2.918 cents per kilowatthour, an increase of 0.063 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $93.87, $0.61 more than the previous month.

The Company's fuel composite cost of generation increased 7.95 cents per million BTU to 596.95 cents per million BTU. The composite cost of purchased energy increased 0.190 cents per kilowatthour to 4.485 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning May 1, 2003.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

May 30, 2003

FILED
2003 MAY 30 P 3:53
PUBLIC UTILITY COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for June 2003 is 2.734 cents per kilowatthour, a decrease of 0.184 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $92.53, $1.34 less than the previous month.

The Company's fuel composite cost of generation decreased 24.53 cents per million BTU to 572.42 cents per million BTU. The composite cost of purchased energy decreased 0.035 cents per kilowatthour to 4.450 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning June 1, 2003.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

FILED

2003 JUN 30 P 3:41

PUBLIC UTILITIES COMMISSION

June 30, 2003

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for July 2003 is 2.330 cents per kilowatthour, a decrease of 0.404 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $90.11, $2.42 less than the previous month.

The Company's fuel composite cost of generation decreased 25.67 cents per million BTU to 546.75 cents per million BTU. The composite cost of purchased energy decreased 0.454 cents per kilowatthour to 3.996 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning July 1, 2003.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

July 31, 2003

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for August 2003 is 2.240 cents per kilowatthour, a decrease of 0.090 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $89.15, $0.96 less than the previous month.

The Company's fuel composite cost of generation decreased 7.93 cents per million BTU to 538.82 cents per million BTU. The composite cost of purchased energy increased 0.047 cents per kilowatthour to 4.043 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning August 1, 2003.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

August 29, 2003

FILED
2003 AUG 29 P 12:49
PUBLIC UTILITY COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for September 2003 is 2.130 cents per kilowatthour, a decrease of 0.110 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $88.49, $0.66 less than the previous month.

The Company's fuel composite cost of generation decreased 7.85 cents per million BTU to 530.97 cents per million BTU. The composite cost of purchased energy decreased 0.115 cents per kilowatthour to 3.928 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning September 1, 2003.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

September 30, 2003

FILED
2003 SEP 30 P 1:42
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for October 2003

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

October 31, 2003

FILED
2003 OCT 31 P 4: 08
PUBLIC UTILITIES
COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for November 2003 is 2.048 cents per kilowatthour, an increase of 0.007 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $88.00, $0.04 more than the previous month.

The Company's fuel composite cost of generation decreased 13.14 cents per million BTU to 512.75 cents per million BTU. The composite cost of purchased energy increased 0.113 cents per kilowatthour to 3.954 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning November 1, 2003.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

November 28, 2003

The Honorable Chairman and Members of

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

December 31, 2003

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COMMI

The Honorable Chairman and Members of

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

January 30, 2004

FILED
2004 JAN 30 P 4:10
PUBLIC UTILITY COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for February 2004 is 2.599 cents per kilowatthour, an increase of 0.027 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $91.42, $0.16 more than the previous month.

The Company's fuel composite cost of generation increased 13.38 cents per million BTU to 578.41 cents per million BTU. The composite cost of purchased energy decreased 0.098 cents per kilowatthour to 4.154 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning February 1, 2004.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

February 27, 2004

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for March 2004 is 2.726 cents per kilowatthour, an increase of 0.127 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $92.19, $0.77 more than the previous month.

The Company's fuel composite cost of generation decreased 21.28 cents per million BTU to 557.13 cents per million BTU. The composite cost of purchased energy increased 0.429 cents per kilowatthour to 4.583 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning March 1, 2004.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

March 31, 2004

FILED
2004 MAR 31 P 4: 10
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for April 2004 is 2.698 cents per kilowatthour, a decrease of 0.028 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $92.02, $0.17 less than the previous month.

The Company's fuel composite cost of generation increased 10.52 cents per million BTU to 567.65 cents per million BTU. The composite cost of purchased energy decreased 0.396 cents per kilowatthour to 4.187 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning April 1, 2004.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

April 30, 2004

FILED
2004 APR 30 A 10:59
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for May 2004 is 2.892 cents per kilowatthour, an increase of 0.194 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $93.44, $1.42 more than the previous month.

The Company's fuel composite cost of generation increased 28.16 cents per million BTU to 595.81 cents per million BTU. The composite cost of purchased energy decreased 0.021 cents per kilowatthour to 4.166 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning May 1, 2004.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

May 28, 2004

FILE
2004 MAY 28 P 3
PUBLIC UTILI
COMMISSI

The Honorable Chairman and Members of

Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for June 2004 is 2.750 cents per kilowatthour, a decrease of 0.142 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $93.11, $0.33 less than the previous month.

The Company's fuel composite cost of generation decreased 16.83 cents per million BTU to 578.98 cents per million BTU. The composite cost of purchased energy increased 0.287 cents per kilowatthour to 4.453 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning June 1, 2004.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

June 30, 2004

FILED
2004 JUN 30 P 4: 12
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for July 2004 is 2.811 cents per kilowatthour, an increase of 0.061 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $92.96, $0.15 less than the previous month. The decrease in the bill is due to the reduction in the IRP Cost Recovery Adjustment for the month, which more than offset the increase in the energy cost adjustment factor.

The Company's fuel composite cost of generation increased 17.00 cents per million BTU to 595.98 cents per million BTU. The composite cost of purchased energy decreased 0.088 cents per kilowatthour to 4.365 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning July 1, 2004.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

July 30, 2004

FILED
2004 JUL 30 P 3:24
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for August 2004 is 3.000 cents per kilowatthour, an increase of 0.189 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $94.10, $1.14 more than the previous month.

The Company's fuel composite cost of generation increased 5.53 cents per million BTU to 601.51 cents per million BTU. The composite cost of purchased energy increased 0.104 cents per kilowatthour to 4.469 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning August 1, 2004.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

August 31, 2004

FILED
AUG 31 4 00 PM '04
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for September 2004 is 3.448 cents per kilowatthour, an increase of 0.448 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $96.79, $2.69 more than the previous month.

The Company's fuel composite cost of generation increased 23.28 cents per million BTU to 624.79 cents per million BTU. The composite cost of purchased energy increased 0.589 cents per kilowatthour to 5.058 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning September 1, 2004.

Sincerely,

Patsy H. Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

September 30, 2004

FILED
SEP 30 4 05 PM '04
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for October 2004 is 3.925 cents per kilowatthour, an increase of 0.477 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $99.65, $2.86 more than the previous month.

The Company's fuel composite cost of generation increased 68.25 cents per million BTU to 693.04 cents per million BTU. The composite cost of purchased energy decreased 0.114 cents per kilowatthour to 4.944 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning October 1, 2004.

Sincerely,

for Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

October 29, 2004

FILED
Oct 29 3 48 PM '04
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for November 2004 is 4.382 cents per kilowatthour, an increase of 0.457 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying \$102.42, \$2.77 more than the previous month.

The Company's fuel composite cost of generation increased 31.05 cents per million BTU to 724.09 cents per million BTU. The composite cost of purchased energy increased 0.193 cents per kilowatthour to 5.137 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning November 1, 2004.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

November 30, 2004

FILED
2004 NOV 30 P 3: 11
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for December 2004 is 4.575 cents per kilowatthour, an increase of 0.193 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $103.58, $1.16 more than the previous month.

The Company's fuel composite cost of generation increased 57.56 cents per million BTU to 781.65 cents per million BTU. The composite cost of purchased energy decreased 0.482 cents per kilowatthour to 4.655 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning December 1, 2004.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

December 30, 2004

FILED
2004 DEC 30 A 11:44
PUBLIC UTILITIES
COMMISSION

The Honorable Chairman and Members of
The Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

The Company's energy cost adjustment factor for January 2005 is 3.578 cents per kilowatthour, a decrease of 0.997 cents per kilowatthour from last month. A residential customer consuming 600 kilowatthours of electricity will be paying $97.60, $5.98 less than the previous month.

The Company's fuel composite cost of generation decreased 68.61 cents per million BTU to 713.04 cents per million BTU. The composite cost of purchased energy decreased 0.443 cents per kilowatthour to 4.212 cents per kilowatthour.

The attached sheets set forth the energy cost adjustment factor in cents per kilowatthour for each rate schedule that is applicable for prorata use beginning January 1, 2005.

Sincerely,

Patsy H Nanbu

Patsy H. Nanbu
Director, Regulatory Affairs

Attachments

cc: Division of Consumer Advocacy

Hawaiian Electric Company, Inc • PO Box 2750 • Honolulu, HI 96840-0001

FILED

APR 30 3 50 PM '03

PUBLIC UTILITIES COMMISSION

April 30, 2003

William A. Bonnet
Vice President
Government and Community Affairs

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 01-0409 – HECO, MECO
Recovery of 2002 IRP Planning Costs

Attached is HECO's Integrated Resource Planning ("IRP") Cost Recovery Adjustment, which is proposed to be effective May 1, 2003 to May 31, 2003. This adjustment recovers the 2002 incremental IRP planning costs, including interest and taxes, in accordance with Stipulated Prehearing Order No. 19952, filed January 8, 2003, Docket No. 01-0409.[1,2,3]

The proposed IRP Cost Recovery Adjustment will be included in the IRP Cost Recovery Provision and will not be shown as a separate line item on customer bills.

In support of the above proposed IRP Cost Recovery Adjustment, attached are:

Exhibit 1	Proposed tariff sheets for the IRP Cost Recovery Adjustment.
Exhibit 2	Tariff sheets currently in effect.

[1] The proposed IRP Cost Recovery Adjustment is for a one-month collection period because the amount to be collected ($192,827) is small relative to the May 2003 forecast base revenues ($63,723,100).

[2] HECO agrees to refund to its customers, with interest at the rate applicable to deferred IRP planning costs, any previously recovered incremental IRP planning costs subsequently disallowed by the Commission in its final Decision and Order in this proceeding.

[3] MECO proposes to recover its 2002 incremental IRP planning costs effective June 1, 2003.

Exhibit 3	Worksheet showing the Determination of the IRP Cost Recovery Adjustment.
Exhibit 4	Worksheet showing the effect of the IRP Cost Recovery Adjustment on a residential customer who uses 600 kilowatt-hours per month.

Sincerely,

Attachments

cc: Division of Consumer Advocacy

Superseding Revised Sheet No. 68
Effective April 1, 2003

REVISED SHEET NO. 68
Effective May 1, 2003

INTEGRATED RESOURCE PLANNING
COST RECOVERY PROVISION

Supplement To

Schedule R	- Residential Service
Schedule E	- Electric Service For Employees
Schedule G	- General Service Non-Demand
Schedule J	- General Service Demand
Schedule H	- Commercial Cooking, Heating, Air Conditioning, and Refrigeration Service
Schedule PS	- Large Power Secondary Voltage Service
Schedule PP	- Large Power Primary Voltage Service
Schedule PT	- Large Power Transmission Voltage Service
Schedule F	- Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U	- Time of Use Service

All terms and provisions of Schedules R, E, G, J, H, PS, PP, PT, F, and U, are applicable except that the total base rate charges for each billing period shall be increased by the following Integrated Resource Planning (IRP) Cost Recovery Adjustment, Residential Demand-Side Management (DSM) Adjustment, and Commercial and Industrial Demand-Side Management (DSM) Adjustment:

A: INTEGRATED RESOURCE PLANNING COST RECOVERY ADJUSTMENT:

All Rate Schedules ....0.303 percent

The total base rate charges for all rate schedules shall be increased by the above Integrated Resource Planning Cost Recovery Adjustment, which is based on the recovery of the 2002 IRP Planning Costs, including interest and taxes, of $192,827 as approved by the Public Utilities Commission.

The total base rate charges for the current billing period shall include all base rate schedule charges, discounts, surcharges, or base

Hawaiian Electric Company, • PO Box 2750 • Honolulu, HI 96840-0001

William A. Bonnet
Vice President
Government and Community Affairs

May 30, 2003

FILED
2003 MAY 30 P 3:56
PUBLIC UTILITY COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 01-0409 – HECO, MECO
<u>Recovery of 2002 IRP Planning Costs</u>

Attached are the proposed tariff sheets that terminate HECO's Integrated Resource Planning ("IRP") Cost Recovery Adjustment, effective June 1, 2003.

A reconciliation of revenues collected for HECO's 2002 IRP Planning Costs, interest, and taxes will be filed in approximately two months.

In support of the proposed termination of the IRP Cost Recovery Adjustment, attached are:

Exhibit 1	Proposed tariff sheets for the IRP Cost Recovery Adjustment.
Exhibit 2	Tariff sheets currently in effect.

Sincerely,

William A. Bonnet

Attachments

cc: Division of Consumer Advocacy

Superseding Revised Sheet No. 68
Effective May 1, 2003

REVISED SHEET NO. 68
Effective June 1, 2003

INTEGRATED RESOURCE PLANNING
COST RECOVERY PROVISION

Supplement To

Schedule R - Residential Service
Schedule E - Electric Service For Employees
Schedule G - General Service Non-Demand
Schedule J - General Service Demand
Schedule H - Commercial Cooking, Heating, Air Conditioning, and Refrigeration Service
Schedule PS - Large Power Secondary Voltage Service
Schedule PP - Large Power Primary Voltage Service
Schedule PT - Large Power Transmission Voltage Service
Schedule F - Public Street Lighting, Highway Lighting and Park and Playground Floodlighting
Schedule U - Time of Use Service

All terms and provisions of Schedules R, E, G, J, H, PS, PP, PT, F, and U, are applicable except that the total base rate charges for each billing period shall be increased by the following Integrated Resource Planning (IRP) Cost Recovery Adjustment, Residential Demand-Side Management (DSM) Adjustment, and Commercial and Industrial Demand-Side Management (DSM) Adjustment:

A: INTEGRATED RESOURCE PLANNING COST RECOVERY ADJUSTMENT:

All Rate Schedules ....0.000 percent

The total base rate charges for all rate schedules shall be increased by the above Integrated Resource Planning Cost Recovery Adjustment, which is based on the recovery of the ____ IRP Planning Costs, including interest and taxes, of $____ as approved by the Public Utilities Commission.

The total base rate charges for the current billing period shall include all base rate schedule charges, discounts, surcharges, or base rate adjustments, excluding the Energy Cost Adjustment, Residential DSM Adjustment, and Commercial and Industrial DSM Adjustment.

B: Residential Demand-Side Management (DSM) Adjustment:

Schedule R - per kwh ....0.2271 ¢/kWh

The total residential monthly bill shall include the above Residential DSM adjustment applied to all kWh per month. The above Residential DSM adjustment is based on recovering $4,644,063 for the 2003 residential program costs and lost revenue margins, the reconciliation of the 2002 program cost recovery including lost revenue margins and revenue taxes, and the 2002 shareholder incentives, for which recovery has been approved by the Public Utilities Commission.

HAWAIIAN ELECTRIC COMPANY, INC.

Transmittal Letter Dated May 30, 2003.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

May 28, 2004

William A. Bonnet
Vice President
Government and Community Affairs

FILED
2004 MAY 28 P 4: 12
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 02-0359 - HECO, MECO
<u>Recovery of 2003 IRP Planning Costs</u>

Attached is HECO's Integrated Resource Planning ("IRP") Cost Recovery Adjustment, which is proposed to be effective June 1, 2004 to June 30, 2004. This adjustment recovers the 2003 incremental IRP planning costs, including interest and taxes, in accordance with Stipulated Prehearing Order No. 19954, filed January 14, 2003, Docket No. 02-0359, and reconciles the collection of the 2002 IRP planning costs, interest, and taxes.[1,2,3] In addition, the Reconciliation Adjustment section of Exhibit 1, page 3 (Revised Sheet No. 68A), is modified to provide for an annual reconciliation adjustment for the IRP Cost Recovery Adjustment to reflect the current reconciliation process.

The proposed IRP Cost Recovery Adjustment will be included in the IRP Cost Recovery Provision and will not be shown as a separate line item on customer bills.

In support of the above proposed IRP Cost Recovery Adjustment, attached are:

Exhibit 1	Proposed tariff sheets for the IRP Cost Recovery Adjustment.
Exhibit 2	Tariff sheets currently in effect.

---

[1] The proposed IRP Cost Recovery Adjustment is for a one-month collection period because the amount to be collected ($452,345) is small relative to the June 2004 forecast base revenues ($65,033,900).

[2] HECO agrees to refund to its customers, with interest at the rate applicable to deferred IRP planning costs, any previously recovered incremental IRP planning costs subsequently disallowed by the Commission in its final Decision and Order in this proceeding.

[3] MECO proposes to recover its 2003 incremental IRP planning costs effective June 1, 2004. MECO's IRP Cost Recovery Adjustment will be filed under a separate transmittal.

The Honorable Chairman a Members of
the Hawaii Public Utilities Commission
May 28, 2004
Page 2

Exhibit 3	Worksheets showing the Determination of the IRP Cost Recovery Adjustment.
Exhibit 4	Worksheet showing the effect of the IRP Cost Recovery Adjustment on a residential customer who uses 600 kilowatt-hours per month.

Sincerely,

Attachments

cc: Division of Consumer Advocacy

~~Revised Sheet No. 68~~ REVISED SHEET NO. 68

COST RECOVERY PROVISION

Supplement To

Schedule R - Residential Service
Schedule TOU-R - Residential Time-of-Use Pilot Program
Schedule E - Electric Service For Employees
Schedule G - General Service Non-Demand
Schedule J - General Service Demand

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

August 31, 2004

FILED
Aug 31 3 43 PM '04
PUBLIC UTILITIES COMMISSION

William A. Bonnet
Vice President
Government and Community Affairs

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 02-0359 – HECO, MECO
<u>Recovery of 2003 IRP Planning Costs</u>

[redacted]

DOD/HECO-IR-2-2

Referring to the Embedded Cost of Service Study in HECO-WP-2202, pages 1 through 173, please provide an electronic copy in Microsoft Excel format, will all formulas intact, including all cost of service studies and all functionalization, classification, allocation and unitization at present rates, proposed rates and at equal rates of return.

HECO Response:

The requested electronic copy of HECO-WP-2202, pages 1 through 173 was provided to the DOD and the Commission via HECO's transmittal letter dated March 30, 2005. Copy was also provided to the Consumer Advocate on January 11, 2005.

DOD/HECO-IR-2-3

Referring to HECO-WP-2202, page 83 of 173, please provide workpapers showing the calculation of the following Embedded Cost of Service Study allocation factors:

a. Average Excess Demand (D1)

b. Composite NCD (D3)

HECO Response:

An electronic copy of HECO-WP-2202, page 83 of 173, showing the calculation of the Average Excess Demand (D1) and Composite NCD (D3), was provided to the DOD and the Commission via HECO's transmittal letter dated March 30, 2005. Copy was provided to the Consumer Advocate on January 11, 2005.

DOD/HECO-IR-2-4

Referring to the Energy Cost Adjustment Clause, as proposed, appearing on Pages 31 and 32 of HECO-106, please provided the supporting detail for the proposed new base costs for fuel and purchased power, including the cost of each individual source in each category, the percentage weighting of each source in each category, and the workpapers showing quantities, cost per unit prices, and the weighted average values.

HECO Response:

Refer to HECO-WP-1032 for details of the proposed new base costs for fuel and purchased power, including the cost of each individual source in each category, the percentage weighting of each source in each category, workpapers and references showing quantities, cost per unit prices and the weighted average values.

DOD/HECO-IR-2-5

Referring to HECO T-1, Page 10, please provide a copy of the Adequacy of Supply report filed on March 31, 2004.

HECO Response:

See pages 2 to 21 to this response for HECO's Adequacy of Supply letter and report filed with the Commission and the Consumer Advocate on March 31, 2004.

March 31, 2004

William A. Bonnet
Vice President
Government and Community Affairs

FILED
2004 MAR 31 P 4:10
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of the
Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Adequacy of Supply
Hawaiian Electric Company, Inc.

HECO's 2003 total generating capability of 1,615,000 kW-net includes 406,000 kW-net of firm power purchased from (1) Kalaeloa Partners, L.P., (2) AES Hawaii, Inc., and (3) H-POWER. Oahu had a reserve margin of approximately 28% over the 2003 system net peak.[3]

HECO also has power purchase contracts with two as-available energy producers. Since these contracts are not for firm capacity, they are not reflected in HECO's total generating capability.

<u>February 2004 Peak Forecast</u>

As indicated in HECO's letter, dated January 30, 2004, requesting an extension of time to file this report, load is expected to grow at a rate faster than previously forecasted over the next five-year period, although there may be a temporary lag due to the deployment of troops from the 25th Infantry Division at Schofield to Iraq. Table 1 shows a comparison of the forecasted peaks for the period 2004–2006 in the August 2002 long-term peak forecast and the February 2004 long-term peak forecast.

Table 1
Comparison of Forecasted Peak Loads
(With Future DSM[4] and Utility CHP and Impacts of Third Party CHP and Rider I)

Year	August 2002 Forecast System Peak (net kW)	February 2004 Forecast System Peak (net kW)	Increase in Peak Forecast (kW)
2004	1,263,000	1,279,500	16,200
2005	1,273,900	1,309,000	35,100
2006	1,286,100	1,334,200	48,100

The major reasons for the higher forecast peaks are a more optimistic near-term economic outlook and substantial new project loads associated with military forward deployment, transformation, and housing privatization. As shown in Attachment 1, pages 2-3, the local economic outlook has improved since the summer of 2002. Major military forward deployment and transformation projects are shown in Attachment 1, page 4. The August 2002 forecast did not include these new military project loads.

The year 2003 provided a solid foundation for economic growth. However, while housing construction and consumer spending were sources of strength, tourism provided only

3 The reserve margin calculation takes into account the 4,000 kW interruptible load served by HECO.
4 HECO's energy efficiency DSM and load management programs.

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
March 31, 2004
Page 3

nominal growth. With a rebound in visitor figures expected this year, all three major sectors (tourism, construction, and military spending) are forecasted to contribute to economic growth in 2004 and beyond.

Strong U.S. economic growth, as shown in Attachment 1 page 5, should support an expansion of domestic visitors to the islands. Visitors from Japan should grow in double digits since even the continuation of late year 2003 visitor levels would be much improved from the depths experienced just prior to and during last year's war in Iraq.

Construction should be even better than last year. With a growing economy, interest rates projected to rise only slightly (as shown in Attachment 1, page 6), and a shortage of housing, the residential market for new and re-sold properties will remain hot. In addition, at least four high-rise condominiums will be under construction. Construction began on the Hokua Condo in Kakaako in November and was expected to start on the Koolani, Moana Pacific, and Lanikea in early 2004. Waikiki is also undergoing revitalization as older apartments and older, off-beach, hotels are renovated into residential and time-share properties.

Military housing will provide another huge boost. Not only will current military construction quality of life projects continue at Schofield and Pearl Harbor, but also the military's housing privatization projects, worth $3.5 billion in construction alone, will start gearing up this year. Actus Lend Lease won both the Army's contract to renovate and replace 7,700 homes over 10 years, and the Air Force's contract for 1,350 homes over a period of 5 years. Hawaii Military Communities won the Navy's contract to renovate and replace more than 1,900 homes over 4 years. Fluor Hawaii also is working with the Navy to provide about $85 million in design-build projects on Ford Island, and will oversee rental property at Iroquois Point, Puuloa, and Kalaeloa. All of these contracts are particularly favorable to the developers because the source of funding is secure, construction is not subject to the vagaries of interest rates, and being on federal land, entitlements are not an issue. Construction is expected to begin as early as April 2004.

The impact of the military construction program on the economy will be immense. State construction put-in-place is expected to grow over 17% in 2004 after a 7% increase last year. It has been estimated that over time, more than 12,000 direct blue and white collar jobs will be added. Furthermore, this does not include the trickle down effect in other sectors that will result from the additional spending by the new job holders.

On the other hand, the military will also have a temporary negative effect on the economy when over 8,000 soldiers deploy to Iraq and Afghanistan this year for 12 months. An unknown number of families also will depart for the mainland when their spouses are deployed. Estimates of the number of families that will leave range from 10% to 40%.

Schofield Barracks is not the only base affected by deployments. Kaneohe Marine Corps Base Hawaii has a "steady state" deployment of approximately 2,000 Marines and expects another 500 this year. Nearly 400 Hawaii Army reservists are expected to leave for Iraq in March 2004. According to the Hawaii National Guard, about 2,100 Hawaii Guardsmen may be sent to Iraq sometime in 2005. The 8,000 Schofield soldiers are scheduled to return to Hawaii early that year.

Overall, however, the outlook for tourism, construction and the military results in an optimistic forecast for the Hawaii economy and related growing demand for electricity. Attachment 1, page 7, compares the forecasts from a number of local economists for 2004. Note that all agree that (1) the visitor industry will rebound this year, (2) job growth will continue to grow at around 2%, and (3) real personal income will grow about 3% or better. Although none of the forecasts shown venture beyond 2004, one thing is certain – military construction will [illegible]

Impact of Higher Peak Demand Forecast

The following method is used to determine the timing of an additional generation unit:

> *The total capability of the system plus the total amount of interruptible loads must at all times be equal to or greater than the summation of the following:*
>
> *a. the capacity needed to serve the estimated system peak load;*
>
> *b. the capacity of the unit scheduled for maintenance; and*
>
> *c. the capacity that would be lost by the forced outage of the largest unit in service.*

The method used to determine the timing of an additional generation unit accounts for interruptible loads. HECO will not build reserve capacity to serve interruptible loads.

Also included in HECO's capacity planning criteria is a reliability guideline. The guideline states:

> *"Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study. In cases where risk is calculated to be less than 4.5 years per day, the plan will be reviewed by the Vice President of Power Supply and the President for approval of use of the plan in the study."*

HECO applies this guideline in determining the need date for new firm capacity.

In HECO's IRP-2 Evaluation Report, filed with the Commission on December 31, 2002, pursuant to PUC Order No. 19689, in Docket No. 95-0347, a modified preferred plan was established. The modified preferred plan reflected the effects of changes in assumptions that occurred between January 1998, when HECO's IRP-2 was filed, and December 2002, when HECO's IRP-2 Evaluation Report was filed. The supply-side of the modified preferred plan called for, among other things, installation of a simple cycle combustion turbine in 2009. The 2009 need date was determined using the August 2002 forecast, part of which is shown in Table 1 above, and by the application of the reliability guideline.

With the February 2004 forecast, which is higher than the August 2002 forecast as indicated in Table 1, HECO's analysis indicates that generating system reliability will fall below the 4.5 years per day reliability guideline beginning in 2006, assuming that no new central-station generating capacity is added from 2004 through 2006, even if:

1. forecasted peak reduction benefits (estimated at 11 MW for 2004 – 2006) from continuation of existing energy efficiency DSM programs are acquired,
2. proposed peak reduction benefits (estimated at 28 MW for 2004 – 2006) from the two load management programs[5] are acquired, as forecasted in their respective applications; and
3. proposed utility CHP impacts (estimated at 8 MW for 2004 – 2006) occur as forecasted in Docket No. 03-0366.

Should the forecasted peak reduction benefits from these programs not occur, then the generating system reliability is expected to fall below the 4.5 years per day reliability guideline threshold sooner than 2006.

Assuming that the aforementioned forecasted peak reduction benefits from these programs do occur, it is estimated that about 30 MW of additional peak reduction benefits, or equivalent capacity additions, would be needed from 2004 through 2006, over and above these programs, to maintain generating system reliability above the 4.5 years per day guideline to 2007. It is also estimated that an additional 10 MW (over and above the 30 MW) of peak reduction benefits, or equivalent capacity additions, would be needed from 2004 through 2008 to maintain generating system reliability above the guideline to 2009.

Utility Combined Heat and Power Program Impacts

On October 10, 2003, HECO (along with MECO and HELCO) filed a PUC Application for approval of a proposed utility-owned Combined Heat and Power ("CHP") Program in Docket No. 03-0366. Implementation of a CHP Program was scheduled to begin in 2004, if authorized by the Commission[6]. The utilities' program involves the installation of small, distributed generating ("DG") units at selected customer sites. The waste heat from the DG units at these selected customer sites would be used for the customers' heating and/or cooling purposes. As indicated in the PUC Application, HECO developed a forecast of utility CHP systems for Oahu (dated August 20, 2003).

CHP systems can also be owned and operated by third-parties (non-utility entities). HECO developed forecasts for third-party CHP systems with and without the utility CHP

[5] HECO filed an application for a Residential Direct Load Control Program in May 2003 in Docket No. 03-0166 and an application for a Commercial & Industrial Dispatchable Load Control Program in December 2003, in Docket No. 03-0415.

[6] The utilities requested approval of each of their proposed CHP Program and related tariff provisions (Schedule CHP, Customer-Sited Utility-Owned Cogeneration Service). Under the CHP Program and Schedule CHP, the utilities propose to offer CHP systems to eligible utility customers on the islands of Oahu, Maui, and Hawaii as a regulated utility service. The utilities also indicated that they would request approval on a contract-by-contract basis for CHP system projects that fall outside the scope of the proposed program.

Program (dated August 20, 2003). Both utility and third-party CHP systems have the potential to defer the installation of traditional centralized generation. The rate of installation of CHP systems is estimated to be significantly greater with the utility CHP Program[7].

On October 21, 2003, the Commission issued Order No. 20582 in Docket No. 03-0371, which initiated a proceeding to investigate DG in Hawaii. The Commission anticipated that other matters related to the DG generic proceeding may be considered on a "case-by-case basis". Issues to be addressed in the DG docket included: (1) addressing interconnection matters, (2) determining who should own and operate distributed generation projects, (3) identifying what impacts, if any, distributed generation will have on Hawaii's electric distribution systems and market, (4) defining the role of regulated electric utility distribution companies and the commission in the deployment of distributed generation in Hawaii, (5) identifying the rate design and cost allocation issues associated with the deployment of distributed generation facilities, and (6) developing revisions to the integrated resource planning process, if necessary.

[redacted]

Docket No. 03-0366, in which it recommended that the CHP Program docket be consolidated with the DG docket, or in the alternative, be suspended so as to not "affect the Commission's analysis" in the DG docket. The Consumer Advocate proposed that the Commission analyze situations "where an existing end-user may leave the grid to pursue non-utility options" on a

By Order No. 20831, issued March 2, 2004 in Docket No. 03-0366, the Commission [redacted]

The Commission indicated that its DG docket is intended to "form the basis for rules and regulations deemed necessary to govern participation into Hawaii's electricity market through distributed generation." The Commission noted that "[e]very effort will be made to hold hearings on Docket No. 03-0371 by the end of 2004 and immediately issue a decision and order in that docket."

As a result, HECO's opportunity to file a motion requesting that its CHP Program be

HECO began meetings for its third major integrated resource planning cycle in July 2003. In this third cycle, relevant forecast, financial, demand-side and supply-side (including renewable resource) assumptions will be re-examined in accordance with the Commission's IRP Framework. A resource integration process will be performed, with Advisory Group input, to develop an updated preferred resource plan in accordance with the IRP Framework. The updated resource plan will identify the appropriate characteristics, timing and size of demand-side and supply-side resources to meet near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. HECO must file its IRP-3 plan with the Commission no later than October 31, 2005, but filed a schedule with the PUC to file by March 31, 2005.

Given the long lead time to install a generating unit and the associated uncertainties, HECO believed it was prudent to proceed, in parallel with the on-going IRP process, with at least the early steps involved in permitting the unit. Accordingly, HECO has begun the process to obtain the air permit. This will help preserve the viability of installing additional generating capacity on the system by 2009. Should the IRP-3 process find that the characteristics, timing or size of the next increment of supply-side capacity are different from those currently being pursued, the circumstances will need to be examined at that time to determine an appropriate course of action.

Mitigation Measures

Given that the next generating unit cannot be installed in 2006, HECO is exploring several other options to mitigate the effects of the higher forecast on generating system reliability. These options include, but are not limited to, more aggressive energy and load management DSM programs that acquire increased and accelerated impacts, identification and implementation of CHP projects in addition to those included in HECO's proposed CHP Program, increased output from HECO's existing units within the limits of existing permits, increased output from existing Independent Power Producers, and the installation of DG. HECO is currently evaluating the cost, permitting, schedule and regulatory requirements for these options.

Since the next generating unit cannot be installed by 2006, it is important that the regulatory proceedings for HECO's proposed load management programs and any proposed individual CHP projects move as quickly as possible[9]. Expeditious approval of these initiatives will enable HECO to begin its implementation efforts to begin acquiring the peak reduction benefits of these initiatives in order to mitigate the effect of the higher peak forecast on generating system reliability.

9 In the near future, HECO plans to request interim approval of its proposed load management programs.

Conclusion

HECO's generation capacity for Oahu for the next three years will be sufficiently large to meet all reasonably expected demands for service, contingent upon an expeditious review and approval of the DSM load management programs and CHP Program (or individual contracts, given suspension of the program) now pending with the Commission. Further, given the brighter economic outlook driving a forecast of increased demand for electricity in the three to six year period, HECO anticipates filings for additional measures, including more aggressive DSM programs and individual CHP project applications in the future as well as a request for approval for a new central-station generating unit with a service date of 2009. Expressing this in terms of megawatts, HECO already has planned for, subject to regulatory approval, acquiring the impacts of approximately 78 MWs from DSM energy efficiency programs, DSM load management programs, and utility-sponsored CHP projects through 2008. In addition, HECO anticipates seeking another 40 MW (specifically 30 MW before 2007 and an additional 10 MW before 2009) of combined additional capacity and load reductions through a mix of generation alternatives and demand-side management programs that are critical to maintain HECO's generation system reliability above the reliability guideline until firm capacity from the new central-station generating unit is added in 2009.

As noted, since firm capacity from the new central-station generating unit will not be in place before 2009, HECO's generating system reliability could fall below the 4.5 years per day threshold in 2006 and beyond if other firm generating capacity is not installed by then, or if the peak reduction benefits of additional or accelerated energy efficiency and load management DSM programs and those of CHP or DG are not realized, beginning in 2005.

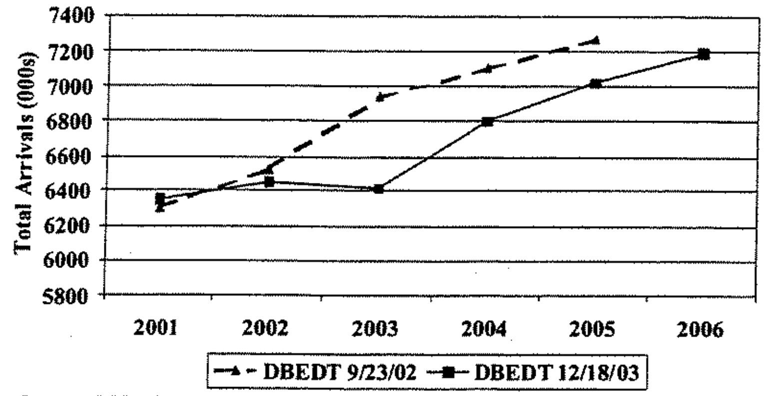
Very truly yours,

Attachment

cc: Division of Consumer Advocacy

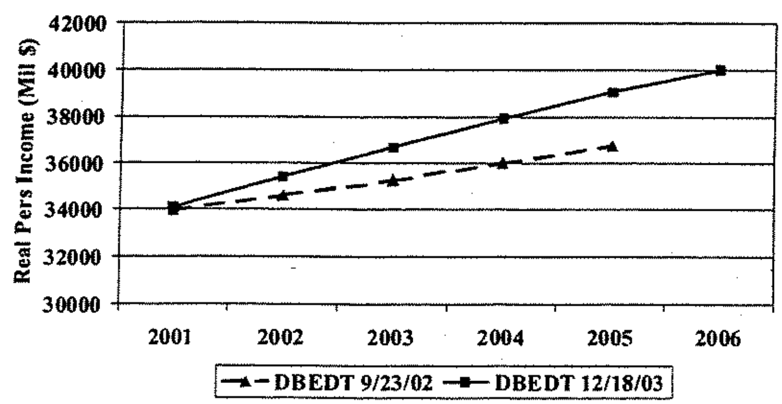
February 04 Peaks Higher Than August 02

State Visitor Arrivals

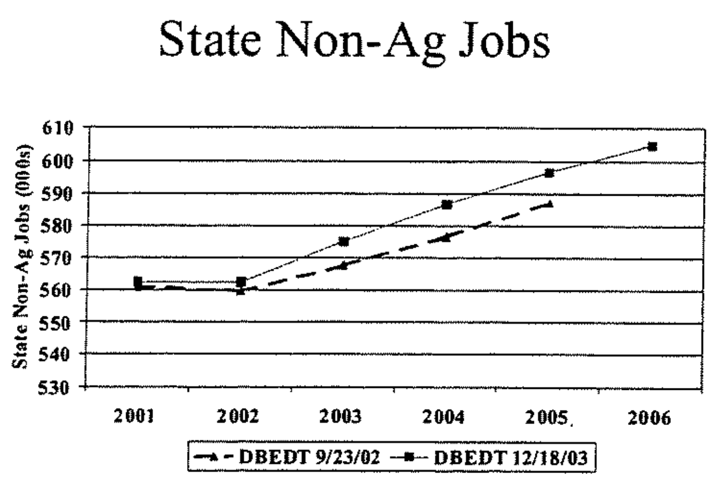


Source: DBEDT Quarterly Economic Outlook, September 23, 2002 and December 18, 2003

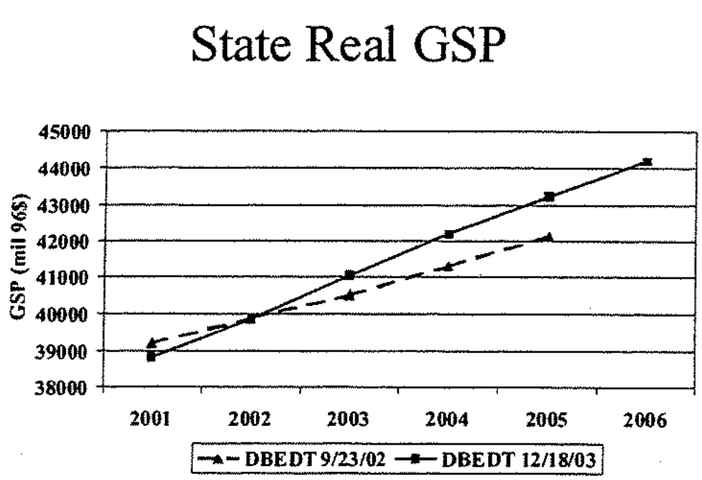
State Real Personal Income



Source: DBEDT Quarterly Economic Outlook, September 23, 2002 and December 18,2003



Source: DBEDT Quarterly Economic Outlook, September 23, 2002 and December 18, 2003



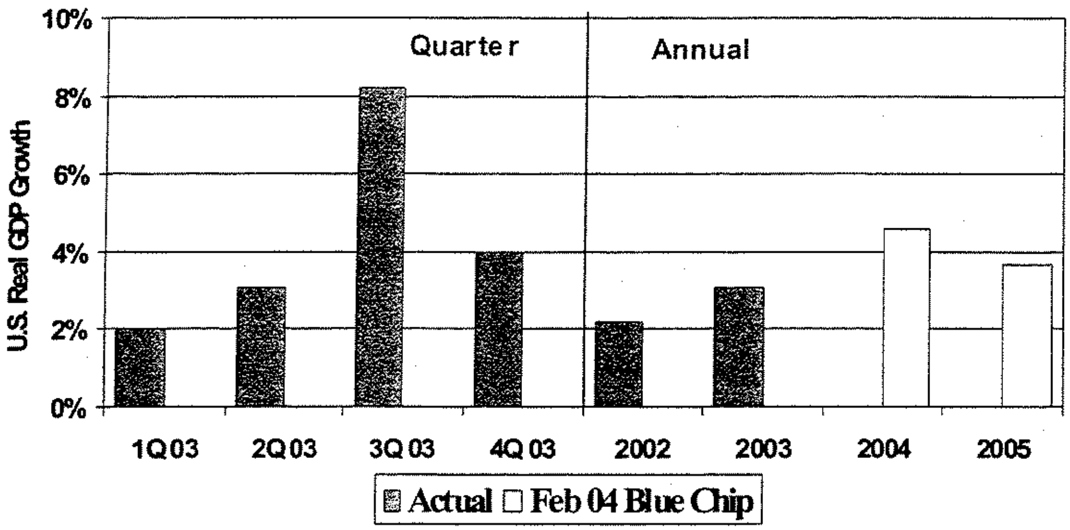
Source: DBEDT Quarterly Economic Outlook, September 23, 2002 and December 18, 2003

Military Forward Deployment/ Transformation Projects

Description	No. of Personnel	No. of Dependents	Date
Stryker Brigade, Schofield	500-800	1600	May 2005
C-17s, Hickam	500	1000	Dec 2005
Aircraft Carrier, Pearl Harbor	3200	4800	July 2009
Carrier Air Wing, Barbers Point	2300	3450	2010

Reference: Projects, personnel, dependents: July 28, 2003, Honolulu Advertiser. Dates: Stryker – FY 2004 Military construction sheet, Information System Facility, p. 61, (http://www.asafm.army.mil/budget/fybm/fy04-05/mcafhha.pdf). C-17s – Sept 24, 2003, Honolulu Advert. Aircraft Carrier and Air Wing – Conversation with Rear Adm. Greenert, Deputy Cmdr. US Pacific Fleet, who indicated that the earliest a carrier could be homeported in Hawaii would be in 5 years.

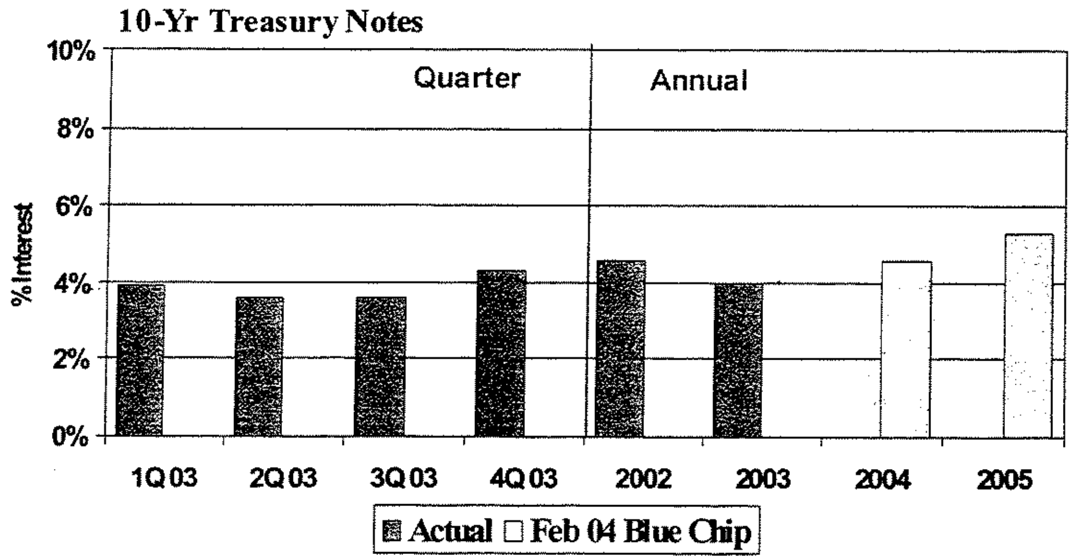
U.S. Real GDP Growth



Source: Blue Chip Economic Indicators, Vol. 29, No. 2, February 10, 2004

Attachment 1
March 31, 2004
Page 6 of 7

Interest Rates



Source: Blue Chip Economic Indicators, Vol. 29, No. 2, February 10, 2004

COMPARISON OF 2003 AND 2004 HAWAII ECONOMIC FORECASTS

	Jobs			Employment			Real Pers Income			CPI		
	2002	2003	2004	2002	2003	2004	2002 [5]	2003	2004	2002	2003	2004
Actual (p)	0.1	2.2		0.3			3.9			1.1	2.3	
BOH [1]		2.3	1.8					3.5	4.0		1.8	1.7
UHERO [2]		2.3	2.0		4.0	2.3		3.4	3.2		1.7	2.5
Laney [3]		2.5	2.0					3.5	2.7		1.8	2.1
DBEDT [4]		2.2	2.0					3.5	3.4		1.8	2.0

	Construction (Current $) [6]			Total Visitor Arrivals			Domestic Arrivals [7]			International Arrivals [8]		
	2002	2003	2004	2002	2003	2004	2002	2003	2004	2002	2003	2004
Actual (p)	13.5			1.4	-0.7		3.2	3.2		-1.4	-9.0	
BOH [1]					1.3	8.3		4.5	3.7		-6.3	14.7
UHERO [2]		7.3	17.4		-0.3	8.7		3.9	4.0		-13.5	24.0
Laney [3]					0.2	3.0						
DBEDT [4]					-0.6	6.0						

[1] Paul Brewbaker, Chief Economist (Bank of Hawaii), September 8, 2003, www.boh.com/econ/pdfs/econ1103.pdf
[2] Professors Carl Bonham and Byron Gangnes (University of Hawaii Economic Research Organization), November 12, 2003
[3] Professor Leroy Laney (Hawaii Pacific University) as reported from FHB annual economic forum, November 20, 2003
[4] Hawaii DBEDT Quarterly Forecast, December 18, 2003
[5] Using Honolulu CPI-U as deflator
[6] UHERO, UHERO Construction Outlook, Construction Put In Place, November 19, 2003
[7] UHERO projections for U.S. arrivals
[8] UHERO projections for Japan arrivals

Attachment 2
March 31, 2004
Page 1 of 3

ADEQUACY OF SUPPLY
Hawaiian Electric Company, Inc.
March 31, 2004

		Without Future DSM (Includes Acquired DSM) (I)		With Future DSM (Includes Acquired DSM) (I)	
Year	System Capability at Annual Peak Load (net kW) [A] (II)	System Peak (net kW) [B] (III)	Reserve Margin (%) [[A-B]/B]	System Peak (net kW) [C] (IV)	Reserve Margin (%) [[A-C]/C]
Recorded					
2003	1,614,600	1,263,000	28%	N/A	N/A
Future					
2004	1,616,800 (V)	1,289,800	25%	1,279,500	26%
2005	1,619,800 (VI)	1,334,200	21%	1,309,000	24%
2006	1,622,400 (VII)	1,374,300	18%	1,334,200	22%

Notes:

(I) Acquired DSM

- Implementation of full-scale DSM programs began in the second half of 1996 following Commission approval of the programs. The forecasted system peaks values for the years 2004-2006 include the actual peak reduction benefits acquired in 1996 - 2002 and also include the peak reduction benefits acquired in 2003 of approximately 4,000 net-kW (net of free riders). Without this 2003 peak reduction benefit, the recorded system net peak of 1,263,000 kW in 2003, which includes 21,000 kW of standby load, would have been 1,267,000 kW.

(II) System Capability includes:

- HECO units at a total normal capability of 1,209,000 kW-net or 1,263,000 kW-gross.
- Firm power purchase contracts have a combined net total of 406,000 kW from Kalaeloa (180,000 kW), AES Hawaii (180,000 kW), and H-POWER (46,000 kW).
- Forecasted utility CHP impacts.[10] Without utility CHP Program impacts, annual system capabilities and corresponding annual reserve margins would be lower.
- When the system capability at the time of the system peak differs from the year-end system capability, an applicable note will indicate the year-end system capability.

[10] Utility CHP impacts are from a CHP forecast dated August 20, 2003. These impacts are at system level based on a T&D loss factor of 4.95%. For capacity planning analysis, an availability factor is also included to account for periods when the utility CHP is unavailable due to forced outage and maintenance.

Attachment 2
March 31, 2004
Page 2 of 3

(III) System Peak (Without Future DSM):

- The 2004-2006 annual forecasted system peaks are based on HECO's February 2004 Long Term Sales and Peak Forecast.
- Forecasted system peaks include the peak reducing impacts of third-party CHP (with utility CHP Program).
- Peaks include 21,000 kW of standby load for the following cogenerators:

Tesoro	19.0
Chevron	0.0
Pearl Harbor	2.0
	21.0 MW

- The HECO annual forecasted system peak is expected to occur in the month of October.
- In addition to acquired DSM, the forecasted system peaks are reduced by 4,000 kW of existing Rider I interruptible loads.

(IV) System Peak (With Future DSM):

- The 2004-2006 annual forecasted system peaks are based on HECO's February 2004 Long Term Sales and Peak Forecast.
- Forecasted system peaks include the peak reducing impacts of third-party CHP (with utility CHP Program).
- Peaks include 21,000 kW of standby load for the following cogenerators:

Tesoro	19.0
Chevron	0.0
Pearl Harbor	2.0
	21.0 MW

- The HECO annual forecasted system peak is expected to occur in the month of October.
- In addition to the acquired DSM, the forecasted system peaks for 2004-2006 include the peak reduction benefits of HECO's energy efficiency DSM programs, load management programs, and Rider I program. On June 6, 2003, HECO filed an Application in Docket No. 03-0166 requesting approval for a proposed residential direct load control program ("RDLC"). On December 11, 2003, HECO filed an Application in Docket No. 03-0415, requesting approval for a proposed Commercial & Industrial Dispatchable Load Control ("CIDLC") program. The estimated peak reductions for these programs begin in 2004.

(V) System Capability at the end of 2004 is 1,617,700 kW (net), which includes additional CHP resources installed after the annual peak and prior to the end of the 2004.

Attachment 2

Page 3 of 3

(VI) System Capability at the end of 2005 is 1,620,300 kW (net), which includes additional CHP resources installed after the annual peak and prior to the end of the 2005.

(VII) System Capability at the end of 2006 is 1,623,500 kW (net), which includes additional CHP resources installed after the annual peak and prior to the end of the 2006.

DOD/HECO-IR-2-6

Within the P-DP customer group in the cost of service study, please provide the number of customers, non-coincident customer demand and kilowatthours (or an estimate of each) associated with customers who receive service at the primary voltage level, but from the low side of a HECO-owned single customer substation that is fed from the HECO transmission system. Also provide the revenues under present rates and under proposed rates associated with such customers.

HECO Response:

The number of customers, non-coincident demand and kilowatthours for the P-DP customer group is provided in HECO-WP-2202, page 83 of 173. An electronic copy of this worksheet was provided to the DOD and the Commission via HECO's transmittal letter dated March 30, 2005. (The electronic worksheet was provided to the Consumer Advocate on January 11, 2005.)

The revenues at proposed rates for the P-DP customer group is provided in HECO-WP-304, page 125 of 154. The revenues at present rates for this customer group can be calculated by multiplying the billing units provided in HECO-WP-304, page 125 of 154, by the customer charge, demand charge, energy charge and secondary metering adjustment provided in the present Schedule PP. A copy of the present Schedule PP is provided in HECO-105, pages 18 through 20.

DOD-IR-2-7

Please provide a copy of HECO's IRP-3 filing, any Commission orders pertaining to IRP-3, and any documents detailing the course of action adopted as the result of the process.

HECO Response:

HECO is unable to provide its IRP-3 filing as it is currently being developed and has not been filed with the Public Utilities Commission. Order No. 20430, dated September 11, 2003, ordered the opening of the docket to commence the next IRP cycle for HECO, is attached as pages 2 through 9. Order No. 20596, dated October 28, 2003, approving HECO's request for an extension of time (from October 13, 2003 to November 7, 2003) to comply with the schedule requirement of Order No. 20430, is attached as pages 10 through 13. Also attached as pages 14 through 15 is a letter from HECO to the PUC dated November 7, 2003, with the schedule HECO developed, in consultation with the Consumer Advocate, for the development of its IRP-3. The letter indicates that HECO originally anticipated filing its IRP-3 by March 31, 2005. HECO has encountered unexpected delays in its IRP process, but still expects to file before October 31, 2005.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

----- In the Matter of -----)
)
HAWAIIAN ELECTRIC COMPANY, INC.) DOCKET NO. 03-0253
)
Regarding Integrated Resource)
Planning.)
)

ORDER NO. 20430

Filed Sept. 11, 2003

At 3:00 o'clock P .M.

Karen Higashi

Chief Clerk of the Commission

ATTEST: A True Copy
KAREN HIGASHI
Chief Clerk, Public Utilities
Commission, State of Hawaii.

K. Higashi

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

----- In the Matter of -----

HAWAIIAN ELECTRIC COMPANY, INC.

Regarding Integrated Resource Planning.

Docket No. 03-0253

Order No. 20430

ORDER

I.

By Decision and Order No. 11523, filed on March 12, 1992, in Docket No. 6617 (as amended by Decision and Order No. 11630, filed on May 22, 1992, the commission established a framework for integrated resource planning ("IRP Framework"), and ordered all energy utilities including HAWAIIAN ELECTRIC COMPANY, INC. ("HECO") to, among other things, submit their integrated resource plans and program implementation schedules for commission approval in accordance with the IRP Framework.

By Decision and Order No. 13839, filed on March 31, 1995, in Docket No. 7257, the commission approved HECO's 1st integrated resource plan ("IRP") and program implementation schedule ("Action Plans").

By Order No. 18340, filed on January 29, 2001, in Docket No. 95-0347, the commission approved the parties'[1] January 17, 2001 Stipulation resolving all of the issues posed in that docket relating to HECO's 2nd IRP and Action Plans. The January 17, 2001 Stipulation provides, among other things, the following agreements and conditions:

1. The parties do not request additional procedural steps or an evidentiary hearing in this proceeding;

2. The parties agree that since HECO's first supply-side generating unit is not required until the 2009 timeframe, concerns raised by the parties with respect to supply-side resources can be more appropriately addressed in HECO's next IRP cycle;

3. The parties agree that concerns raised by the parties with respect to [demand-side management ("DSM")] resources and/or HECO's DSM Action Plan can be more appropriately addressed in HECO's pending DSM program proceedings [in] Docket Nos. 00-0169 and 00-0209;

4. The parties agree that concerns raised with respect to the [Hawaii] Externalities Workbook[, filed on July 22, 1997, ("Externalities Workbook")] can be appropriately addressed in HECO's next IRP cycle;

5. As a result, the parties agree that (a) HECO's [2nd IRP] and Action Plans are sufficient to meet HECO's [responsibilities] under Sections II.C.1[.] [and II.C.2.] of the IRP Framework, and (b) it is not necessary

[1]In addition to HECO, the parties in Docket No. 95-0347 included the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate"), The Department of Navy on behalf of the United States Department of Defense and The Citizens Communications Company, dba The Gas Company (nka, The Gas Company, LLC).

under the circumstances for the [c]ommission to issue a final decision and order under Section II.D.2[.] of the IRP Framework;

6. The parties further agree that, although HECO's [2nd IRP] and Action Plans will have the status of plans filed with, but not approved by, the [c]ommission, HECO may execute the plans pursuant to Section II.C.3. of the IRP Framework as if approved by the [c]omission, and the [2nd IRP] and Action Plans will be considered to the extent deemed appropriate by the [c]ommission in other HECO proceedings pursuant to Section III.D.5[.] of the IRP Framework. Nothing herein will be construed to prohibit HECO or another party from recommending that changes in forecasts (which may impact parts of the [2nd IRP] and Action Plans such as the scheduling of the resource additions)

the filed/IRP ... and/or Action Plans are considered in other proceedings;

7. The parties also agree that (a) HECO has sufficiently complied with the requirement[s] that it submit[s] its externalities findings and recommendations to the [c]ommission by submitting its Externalities Workbook, (b) the Externalities Workbook may be used by HECO in subsequent IRP filings, and (c) nothing herein shall be construed to prohibit HECO or another party from presenting or using other qualitative or quantative externality values and/or methodologies in future IRP proceedings;

8. Pursuant to Section III.D.3[.] of the IRP

> 9. Pursuant to Section III.B.2[.] of the IRP Framework, HECO will submit a revised (third) IRP Plan and Action Plans no later than October 31, 2005, unless the [c]ommission sets or approves a later date for such submission.

By letter filed on September 8, 2003, HECO and the Consumer Advocate jointly request that the commission open a docket for HECO's 3rd IRP cycle, as required under Section III.C.1. of the IRP Framework.[3]

II.

Section III.C.1. of the IRP Framework provides that "[e]ach planning cycle for a utility will commence with the issuance of an order by the commission opening a docket for [IRP]." Thus, in light of HECO's and the Consumer Advocate's representation

---

[3]In their September 8, 2003 joint request, HECO and the Consumer Advocate represent, in relevant part:

> Section III.C. of the IRP Framework indicates the planning cycle will commence with the issuance of an order by the [c]omission to open a docket and the [IRP] Framework contemplates that the utility will complete its IRP Plan and Action Plans within one year of the commencement of the planning cycle. It has taken longer than a year, however, for the utility to complete its planning cycle and the utility has requested extensions of the filing date in the past. Therefore, it is in the public interest that the process for HECO's 3rd IRP Plan begin immediately such that HECO's 3rd IRP Plan is not delayed beyond October 2005.
>
> In addition, an important part of the IRP process is public participation. To better achieve meaningful

in their joint request to open a docket and pursuant to Section III.C.1, of the IRP Framework, the commission finds and concludes that a docket should be opened to commence the next IRP cycle for HECO, and to examine HECO's 3rd IRP to be submitted no later than October 31, 2005. Furthermore, in accordance with Section III.C.3. of the IRP Framework, we also conclude that HECO shall prepare, in consultation with the Consumer Advocate, and file with the commission within 30 days after the date of this order, a schedule that it intends to follow in the development of its 3rd IRP. Unless ordered otherwise, the schedule should also be consistent with the IRP Framework and the terms and conditions of Stipulation approved by the commission in Order No. 18340, filed on January 29, 2001.

III.

THE COMMISSION ORDERS:

1. Pursuant to Section III.C.1. of the IRP Framework, this docket is opened to commence the next IRP cycle for HECO, and to examine HECO's 3rd IRP to be submitted no later than October 31, 2005.

2. HECO shall prepare, in consultation with the [illegible]

after the date of this order, a schedule that it intends to follow in the development of its 3rd IRP. Unless ordered otherwise, the

DONE at Honolulu, Hawaii this 11th day of September, 2003.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By Carlito P. Caliboso
Carlito P. Caliboso, Chairman

By Wayne H. Kimura
Wayne H. Kimura, Commissioner

By (EXCUSED)
Janet E. Kawelo, Commissioner

APPROVED AS TO FORM:

Kris N. Nakagawa
Kris N. Nakagawa
Commission Counsel

HECO IRP.sm

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing Order No. 20430 upon the following parties, by causing a copy hereof to be mailed, postage prepaid, and properly addressed to each such party.

DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS
DIVISION OF CONSUMER ADVOCACY
P. O. Box 541
Honolulu, HI 96809

WILLIAM A. BONNET
VICE PRESIDENT
GOVERNMENT & COMMUNITY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. Box 2750
Honolulu, HI 96840

DATED: September 11, 2003

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

----- In the Matter of -----

HAWAIIAN ELECTRIC COMPANY, INC.

Regarding Integrated Resource Planning.

DOCKET NO. 03-0253

ORDER NO. 20596

Filed Oct. 28, 2003

At 10:00 o'clock A.M.

Karen Higashi

Chief Clerk of the Commission

ATTEST: A True Copy
KAREN HIGASHI
Chief Clerk, Public Utilities Commission, State of Hawaii.

K. Higashi

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

----- In the Matter of -----	
HAWAIIAN ELECTRIC COMPANY, INC.	Docket No. 03-0253
Regarding Integrated Resource Planning.	Order No. 20596

ORDER

I.

Request For An Extension of Time

The commission directed HAWAIIAN ELECTRIC COMPANY, INC. ("HECO") by Order No. 20430 to prepare and file, in consultation with the DIVISION OF CONSUMER ADVOCACY, DEPARTMENT OF COMMERCE AND CONSUMER AFFAIRS ("Consumer Advocate"), a schedule it intends to follow in the development of HECO's 3rd IRP within 30 days after the date of Order No. 20430.[1]

HECO filed a letter on October 10, 2003 requesting an extension of time (from October 13, 2003 to November 7, 2003) to comply with Order No. 20430 ("written request for an extension of time").

[1]Order No. 20430 was filed on September 11, 2003. Thus, pursuant to Hawaii Administrative Rules ("HAR") §§ 6-61-21 and 6-61-22, HECO's schedule was due on October 13, 2003.

II.

Discussion

Pursuant to HAR § 6-61-23(a)(1), when by HAR chapter 61 or by notice or by order of the commission, any act is required or allowed to be done at or within a specified time, we may, for good cause shown and in our discretion, order the period of time enlarged, if written request is made before the expiration of the period originally prescribed.

HECO timely filed its written request for an extension of time on October 10, 2003. Based on HECO's representation, it appears that HECO and the Consumer Advocate need additional time to meet and discuss the schedule HECO intends to follow in the development of HECO's 3rd IRP. HECO also represents that the Consumer Advocate does not object to the written request for an extension of time.

In light of the above, we find good cause to approve HECO's request for an extension of time. Accordingly, we conclude that HECO's request for an extension of time (from October 13, 2003 to November 7, 2003) to comply with Order No. 20430 should be approved.

III.

Order

THE COMMISSION ORDERS that HECO's request for an extension of time (from October 13, 2003 to November 7, 2003) to comply with Order No. 20430 is approved.

DONE at Honolulu, Hawaii this 28th day of October, 2003.

PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

By ______________________
Carlito P. Caliboso, Chairman

By ______________________
Wayne H. Kimura, Commissioner

By ______________________
Janet E. Kawelo, Commissioner

APPROVED AS TO FORM:

____
Kris N. Nakagawa
Commission Counsel

0309253.eh

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

November 7, 2003

William A. Bonnet
Vice President
Government and Community Affairs

FILED
2003 NOV -7 P 4: 09
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building
465 South King Street, 1st Floor
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 03-0253
HECO IRP-3

Pursuant to Order No. 20430[1] filed in this docket, attached is the schedule HECO intends to follow in the development of its third IRP. The schedule was prepared in consultation with the Consumer Advocate.

Sincerely,

cc: Division of Consumer Advocacy

1 Order No. 20430 required HECO to submit a schedule by October 13, 2003. HECO's request for an extension of time until November 7, 2003 to submit a schedule was approved by the Commission by Order No. 20596.

HECO IRP-3 Advisory Group Schedule

1	Orientation sessions	Sept. 24 & Oct 3, 2003	
2	Kick-off, organizational items, draft IRP-3 objectives	Oct. 7, 2003	
3	Public meeting: Input on IRP objectives (evening meeting)	Oct. 29, 2003	
4	Load Forecast and DSM Committees meetings	Mid Nov 2003 - Mid Feb 2004	*
5	Announce 2002 IRP Evaluation is on Web site	Nov. 10, 2003	
6	Advisory Group Meeting: Draft scope of IRP-3	Dec. 10, 2003	
7	Supply-side and CHP Committees meetings	Late Nov 2003 - Mid Feb 2004	*
8	Integration Committee meetings	Jan 2004 - Late June 2004	*
9	Advisory Group Meeting: Load Forecast, DSM, CHP, and Supply-side Committee results; draft finalist plans	Early March 2004	*
10	Advisory Group Meeting: Integration Committee results	Late June 2004	*
11	Public Meeting: Integration Analysis, Input on Preferred Plan (evening meeting)	Early July 2004	*
12	Advisory Group Meeting: Review Public Comments, Input on Preferred Plan	Late July 2004	*
13	Advisory Group Meeting: Review and comment on draft report	Late Nov 2004	*
14	File HECO IRP-3 report with PUC	Late Mar 2005	

* Specific dates would be coordinated with the Division of Consumer Advocacy.

Note: The above schedule may be amended as appropriate as the IRP process proceeds, due to among other things, issues raised during the process, the time required to address the issues, and the schedules of parties.

DOD/HECO-IR-2-8

Please provide a copy of HECO's Adequacy of Supply letter to the PUC dated March 31, 2004, as mentioned at Line 4 of Page 38 of HECO T-10.

HECO Response:

See HECO response to DOD/HECO-IR-2-5.

DOD/HECO-IR-3-1

Please provide the per books capital structure of Hawaiian Electric Industries, Inc. and Hawaii Electric Company at December 31, 2003 and March 31, and June 30, September 30, and December 31, 2004. For the purposes of this data request, please provide the information as follows:

a. Long-term Debt (including that maturing within one year);

b. Short-term Debt;

c. Other Debt (specify);

d. Preferred or Preference Stock;

e. Common Stock;

f. Additional Paid-in Capital;

g. Retained Earnings; and

h. Total Common Equity (please identify any common equity attributable to unregulated operations, if any).

Also, please provide published balance sheet support for each of the above-requested capital structures.

<u>HECO Response:</u>

Please see attached schedule for the capital structure per books of HECO. The capital structure of Hawaiian Electric Industries, Inc. is as presented in SEC filings 10-Q and 10-K.

HECO (Oahu only)

Capital Structure Ratios

Periods ended	12/31/2003	3/31/2004	6/30/2004	9/30/2004	12/31/2004
Long-term debt	38.8%	37.1%	37.8%	37.6%	36.6%
Short-term debt	1.8%	3.5%	5.5%	4.5%	5.2%
Other debt (hybrid)	5.4%	7.6%	2.6%	2.6%	2.5%
Preferred Stock	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Common Stock	16.7%	15.9%	16.3%	16.2%	15.8%
Additional Paid-in Capital	0.0%	0.0%	0.0%	0.0%	0.0%
Retained Earnings	35.3%	33.9%	35.9%	37.1%	38.0%
Common equity	52.0%	49.9%	52.2%	53.4%	53.8%
	100.0%	100.0%	100.0%	100.0%	100.0%

Balance Sheet support
($ in thousands)

Periods ended	12/31/2003	3/31/2004	6/30/2004	9/30/2004	12/31/2004
Long-term debt	434,824	439,818	436,960	437,445	436,503
Short-term debt	20,700	41,492	63,513	51,972	61,460
Other debt (hybrid)	60,000	90,000	30,000	30,000	30,000
Preferred Stock	22,293	22,293	22,293	22,293	22,293
Common Stock	186,932	188,755	188,754	188,759	188,760
Additional Paid-in Capital					
Retained Earnings	395,630	401,941	414,788	431,443	452,132
Common equity	582,562	590,696	603,542	620,202	640,892
	1,120,379	1,184,299	1,156,308	1,161,912	1,191,148

HEI

Capital Structure Ratios

Periods ended	12/31/2003	3/31/2004	6/30/2004	9/30/2004	12/31/2004
Long-term debt	44.6%	51.9%	48.9%	48.2%	46.9%
Short-term debt	0.0%	0.9%	0.6%	0.3%	3.1%
Other debt	0.0%	0.0%	0.0%	0.0%	0.0%
Preferred Stock	9.8%	1.3%	1.4%	1.4%	1.4%
Common Stock	37.2%	37.5%	42.1%	41.6%	40.6%
Additional Paid-in Capital	0.0%	0.0%	0.0%	0.0%	0.0%
Retained Earnings	8.3%	7.7%	8.0%	8.6%	8.4%
[redacted]					
	100.0%	100.0%	100.0%	100.0%	100.0%

Balance Sheet support
($ in thousands)

Periods ended	12/31/2003	3/31/2004	6/30/2004	9/30/2004	12/31/2004

[redacted]

DOD/HECO-IR-3-2

For the same five time periods referenced in the preceding interrogatory, please provide the following information for Hawaiian Electric Industries, Inc. and Hawaii Electric Company:

a. Embedded cost rates for long-term debt, short-term debt, other debt and preferred or preference stock;

b. Computation of embedded cost rates of long-term debt;

c. Computation of embedded cost rates of short-term debt; and

d. Computation of embedded cost rates of preferred or preference stock.

Note: Schedules should include date of issue, maturity date, dollar amount, coupon rate, net proceeds, annual interest paid and balance of principal, where applicable.

<u>HECO Response:</u>

a. Please see schedule on page 3.

b. Please see schedules on pages 4-6 and 9-13 for computation of long-term debt embedded cost rates.

c. HECO and HEI do not calculate the embedded cost rate of short-term debt. HECO's short-term debt is comprised of commercial paper issuances and intercompany borrowings. HEI's short-term debt is comprised of commercial paper issuances. Each commercial paper issuance has a stated rate which is comprised of the interest to the purchaser of the commercial paper and a fee to the commercial paper broker. HECO and HEI normally issue commercial paper with terms of 30 days or less. There are numerous issuances in any given quarter and the amount outstanding fluctuates throughout the quarter. The individual CP transactions are not compiled to derive a single cost rate for a quarter or any other period. HECO can also borrow funds from HEI, MECO or HELCO. If HECO borrows from MECO or HELCO, HECO pays interest on funds at a rate equal to the simple average of the effective 7-day Treasury Repurchase rate quoted by Merrill Lynch on each Friday during the month. See the response to DOD/HECO-IR-3-6 for information relating to the borrowing rate where HECO borrows funds from HEI.

d. Please see schedules on pages 7 and 8 for computation of preferred stock embedded cost rates for HECO.

HEI (parent company only) preferred securities consisted of HEI Capital Trust I 8.36% Trust Originated Preferred Securities of $100 million at 12/31/03. For financial statement purposes, these preferred securities were consolidated at 12/31/03 and not consolidated for the financial statement quarter ended 3/31/04. The preferred securities were redeemed in April 2004. HEI does not have a calculation of the embedded cost of this security for the periods requested.

Embedded Cost Rates

HECO (Oahu only)

Periods ended	12/31/2003	3/31/2004	6/30/2004	9/30/2004	12/31/2004
Long-term debt (p. 6) [1]	6.45%	*	*	*	6.27%
Short-term debt			see response to (c)		
Preferred stock (p. 8) [2]	5.57%	*	*	*	5.55%

HEI (Parent Company only)

Periods ended	12/31/2003	3/31/2004	6/30/2004	9/30/2004	12/31/2004
Long-term debt (pp. 9-13) [3]	6.32%	6.38%	6.07%	6.07%	6.07%
Short-term debt			see response to (c)		
Preferred stock			see response to (d)		

* The Company did not calculate this information for the specified period.

[1] Based on annual interest requirements/long-term debt balance.

[2] Based on annual requirements/net proceeds.

[3] Based on quarterly interest expense/long-term debt balance * 4.

LONG-TERM DEBT

Hawaiian Electric Company, Inc.

December 31	2004	2003
Obligations to the State of Hawaii for repayment of special purpose revenue bonds:		
5.00%, Series 2003B, due 2022	$ 40,000,000	$ 40,000,000
5.10%, Series 2002A, due 2032	40,000,000	40,000,000
5.70%, Refunding series 2000, due 2020	46,000,000	46,000,000
5.75%, Refunding series 1999B, due 2018	30,000,000	30,000,000
6.20%, Series 1999C, due 2029	35,000,000	35,000,000
6.15%, Refunding series 1999D, due 2020	16,000,000	16,000,000
4.95%, Refunding series 1998A, due 2012	42,580,000	42,580,000
5.65%, Series 1997A, due 2027	50,000,000	50,000,000
5 7/8%, Series 1996B, due 2026	14,000,000	14,000,000
6.20%, Series 1996A, due 2026	48,000,000	48,000,000
6.60%, Series 1995A, due 2025	40,000,000	40,000,000
5.45%, Series 1993, due 2023	50,000,000	50,000,000
Less funds on deposit with trustees	(12,462,000)	(14,013,000)
Total special purpose revenue bonds	439,118,000	437,567,000
Notes payable to associated companies:		
6.50%, QUIDS, due 2034	31,546,400	0
8.05%, QUIDS, due 2027	0	31,546,400
7.30%, QUIDS, due 2028	0	31,546,400
	31,546,400	63,092,800
Total long-term debt[1]	470,664,400	500,659,800
Less unamortized discount on revenue bonds	(2,615,026)	(2,744,286)
Total long-term debt, net	$468,049,374	$497,915,514

LONG-TERM DEBT INTEREST REQUIREMENTS ON DEBT OUTSTANDING AT DECEMBER 31 (Annual Basis)

Hawaiian Electric Company, Inc.

December 31	2004	2003
Interest on special purpose revenue bonds:		
5.00%, Series 2003B	$ 2,000,000	$ 2,000,000
5.10%, Series 2002A	2,040,000	2,040,000
5.70%, Refunding series 2000	2,622,000	2,622,000
5.75%, Refunding series 1999B	1,725,000	1,725,000
6.20%, Series 1999C	2,170,000	2,170,000
6.15%, Refunding series 1999D	984,000	984,000
4.95%, Refunding series 1998A	2,107,710	2,107,710
5.65%, Series 1997A	2,825,000	2,825,000
5 7/8%, Series 1996B	822,500	822,500
5.20%, Series 1996A	2,976,000	2,976,000
6.60%, Series 1995A	2,640,000	2,640,000
5.45%, Series 1993	2,725,000	2,725,000
	25,637,210	25,637,210
Interest on notes payable to associated companies:		
6.50%, QUIDS, due 2034	2,050,516	0
8.05%, QUIDS, due 2027	0	2,539,485
7.30%, QUIDS, due 2028	0	2,302,887
	2,050,516	4,842,372
	27,687,726	30,479,582

LONG-TERM DEBT INTEREST REQUIREMENTS
ON DEBT OUTSTANDING AT DECEMBER 31
(Annual Basis) (continued)
Hawaiian Electric Company, Inc.

December 31	2004	2003
Balance brought forward	$27,687,726	$30,479,582
Amortization of debt expense and premium:		
First mortgage bonds [1]:		
Series T	0	46,548
Series U	129,770	141,567
Series V	61,968	61,968
Series X	66,633	66,633
Special purpose revenue bonds:[2]		
[illegible]	[illegible]	[illegible]
5.10%, Series 2002A	45,727	42,353
5.70%, Refunding series 2000	153,258	153,258
5.75%, Refunding series 1999B	117,854	117,854
6.20%, Series 1999C	37,330	37,330
6.15%, Refunding series 1999D	50,403	50,403
4.95%, Refunding series 1998A	216,748	216,748
5.65%, Series 1997A	54,136	54,136
5 7/8%, Series 1996B	18,844	18,844
6.20%, Series 1996A	77,315	77,315
6.60%, Series 1995A	80,997	80,997
5.45%, Series 1993	78,254	78,254
Special purpose revenue bonds retired:		
Series 1982	45,762	45,762
Series 1987	116,739	116,739
Series 1988	59,945	59,945
Series 1990A	29,573	29,573
Series 1990B	36,552	36,552
Series 1990C	50,196	50,196
Series 1992	93,736	93,736
QUIDS, 6.50%	24,620	0
QUIDS, 8.05%	40,250	40,221
QUIDS, 7.30%	37,745	37,718
	1,802,493	1,804,507

PREFERRED STOCK
Hawaiian Electric Company, Inc.

December 31				2004	2003
Cumulative preferred stock: Authorized: 2002-1997, 5,000,000 shares of $20 par value and 5,000,000 shares of $100 par value.					
Series	Par Value	Shares Outstanding December 31, 2002	Date Issued		
Series not subject to mandatory redemption:					
C-4 1/4%	$20	150,000	October 22, 1945	$3,000,000	$3,000,000
D-5%	20	50,000	August 16, 1948	1,000,000	1,000,000
E-5%	20	150,000	March 20, 1950	3,000,000	3,000,000
H-5 1/4%	20	250,000	October 14, 1960	5,000,000	5,000,000
I-5%	20	89,657	August 15, 1961	1,793,140	1,793,140
J-4 3/4%	20	250,000	June 5, 1962	5,000,000	5,000,000
K-4.65%	20	175,000	January 27, 1964	3,500,000	3,500,000
M-8.05%	100	--	September 27, 1971	--	--
		1,114,657		22,293,140	22,293,140
Series subject to mandatory redemption:					
Q-7.68%	100	--	December 1, 1986	--	--
R-8.75%	100	--	December 22, 1989	--	--
		--		--	--
Total cumulative preferred stock				$22,293,140	$22,293,140

PREFERRED STOCK DIVIDEND REQUIREMENTS (Annual Basis)

Hawaiian Electric Company, Inc.

December 31	2004	2003
Preferred stock dividends:		
Series C, 4 1/4%	$ 127,500	$ 127,500
Series D, 5%	50,000	50,000
Series E, 5%	150,000	150,000
Series H, 5 1/4%	262,500	262,500
Series I, 5%	89,657	89,657
Series J, 4 3/4%	237,500	237,500
Series K, 4.65%	162,750	162,750
Total annual dividends	1,079,907	1,079,907
Amortization of preferred stock expenses	55,086	55,086
Total annual requirements	$ 1,134,993	$ 1,134,993

Preferred stock outstanding	$ 22,293,140	$ 22,293,140
Unamortized preferred stock expenses:		
Series C	70,404	70,404
Series D	55,071	55,071
Series E	183,556	183,556
Series H	59,679	59,679
Series I	64,701	64,701
Series J	49,654	49,654
Series K	39,755	39,755
Series M	170,648	177,758
Series Q	675,709	703,863
Series R	475,704	495,525
Total unamortized preferred stock expenses	1,844,881	1,899,966
Net proceeds	$ 20,448,259	$ 20,393,174
Embedded cost of preferred stock	5.55%	5.57%

HEI
LONG-TERM DEBT
December 2003

Description	12/31/03 Principal Balance	Date of Note	Maturity Date	Interest Rate	Payment Dates	Annual Interest Paid	Annual Accrued Interest	4Q03 Accrued Interest	Net Proceeds
Series B - MTN	30,000,000	12/05/95	12/05/05	6.660%	4/10, 10/10	1,998,000	1,998,000	499,500	29,812,500
Series B - MTN	10,000,000	02/14/96	02/14/06	6.545%	4/10, 10/10	654,500	654,500	163,625	9,937,500
Series B - MTN	7,000,000	10/01/97	10/01/12	7.130%	4/10, 10/10	499,100	499,100	124,775	6,951,000
Series B - MTN	5,000,000	10/1/97	10/01/07	6.930%	4/10, 10/10	346,500	346,500	86,625	4,968,750
Series B - MTN	5,000,000	10/1/97	10/01/07	6.900%	4/10, 10/10	345,000	345,000	86,250	4,968,750
Series B - MTN	1,000,000	10/02/97	10/04/04	6.800%	4/10, 10/10	68,000	68,000	17,000	994,000
Series B - MTN	1,000,000	10/6/97	10/06/05	6.830%	4/10, 10/10	68,300	68,300	17,075	994,000
Series B - MTN	6,000,000	06/09/98	06/15/05	6.630%	4/10, 10/10	397,800	397,800	99,450	5,964,000
Series C - MTN	100,000,000	05/05/99	05/05/14	6.510%	4/10, 10/10	6,510,000	6,510,000	1,627,500	99,400,000
Series C - MTN	100,000,000	04/09/01	04/10/06	7.560%	4/10, 10/10	7,560,000	7,560,000	1,890,000	99,500,000
Series D - MTN	50,000,000	03/07/03	03/07/08	4.000%	3/7, 9/7	1,000,000	1,633,333	500,000	49,750,000
Series D - MTN	50,000,000	03/07/03	03/07/13	5.250%	3/7, 9/7	1,312,500	2,143,750	656,250	49,687,500
	365,000,000					20,759,700	22,224,283	5,768,050	362,928,000

Annualized weighted average interest rate 6.32%

HEI
LONG-TERM DEBT
March 2004

Description	03/31/04 Principal Balance	Principal O/S For 1Q04	Date of Note	Maturity Date	Interest Rate	Payment Dates	Annual Interest Paid	Annual Accrued Interest	1Q04 Accrued Interest	Net Proceeds
Series B - MTN	30,000,000	30,000,000	12/05/95	12/05/05	6.660%	4/10, 10/10	1,998,000	1,998,000	499,500	29,812,500
Series B - MTN	10,000,000	10,000,000	02/14/96	02/14/06	6.545%	4/10, 10/10	654,500	654,500	163,625	9,937,500
Series B - MTN	7,000,000	7,000,000	10/01/97	10/01/12	7.130%	4/10, 10/10	499,100	499,100	124,775	6,951,000
Series B - MTN	5,000,000	5,000,000	10/1/97	10/01/07	6.930%	4/10, 10/10	346,500	346,500	86,625	4,968,750
Series B - MTN	5,000,000	5,000,000	10/1/97	10/01/07	6.900%	4/10, 10/10	345,000	345,000	86,250	4,968,750
Series B - MTN	1,000,000	1,000,000	10/02/97	10/04/04	6.800%	4/10, 10/10	66,867	51,378	17,000	994,000
Series B - MTN	1,000,000	1,000,000	10/6/97	10/06/05	6.830%	4/10, 10/10	68,300	68,300	17,075	994,000
Series B - MTN	6,000,000	6,000,000	06/09/98	06/15/05	6.630%	4/10, 10/10	397,800	397,800	99,450	5,964,000
Series C - MTN	100,000,000	100,000,000	05/05/99	05/05/14	6.510%	4/10, 10/10	6,510,000	6,510,000	1,627,500	99,400,000
Series C - MTN	100,000,000	100,000,000	04/09/01	04/10/06	7.560%	4/10, 10/10	7,560,000	7,560,000	1,890,000	99,500,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/08	4.000%	3/7, 9/7	2,000,000	2,000,000	500,000	49,750,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/13	5.250%	3/7, 9/7	2,625,000	2,625,000	656,250	49,687,500
Series D - MTN	50,000,000	1,912,568	03/17/04	03/15/11	4.230%	3/15, 9/15	1,045,750	1,674,375	80,902	49,700,000
	415,000,000	366,912,568					24,116,817	24,729,953	5,848,952	412,628,000

Annualized weighted average interest rate 6.38%

HEI
LONG-TERM DEBT
June 2004

Description	06/30/04 Principal Balance	Date of Note	Maturity Date	Interest Rate	Payment Dates	Annual Interest Paid	Annual Accrued Interest	2Q04 Accrued Interest	Net Proceeds
Series B - MTN	30,000,000	12/05/95	12/05/05	6.660%	4/10, 10/10	1,998,000	1,998,000	499,500	29,812,500
Series B - MTN	10,000,000	02/14/96	02/14/06	6.545%	4/10, 10/10	654,500	654,500	163,625	9,937,500
Series B - MTN	7,000,000	10/01/97	10/01/12	7.130%	4/10, 10/10	499,100	499,100	124,775	6,951,000
Series B - MTN	5,000,000	10/1/97	10/01/07	6.930%	4/10, 10/10	346,500	346,500	86,625	4,968,750
Series B - MTN	5,000,000	10/1/97	10/01/07	6.900%	4/10, 10/10	345,000	345,000	86,250	4,968,750
Series B - MTN	1,000,000	10/02/97	10/04/04	6.800%	4/10, 10/10	66,867	51,338	17,000	994,000
Series B - MTN	1,000,000	10/6/97	10/06/05	6.830%	4/10, 10/10	68,300	68,300	17,075	994,000
Series B - MTN	6,000,000	06/09/98	06/15/05	6.630%	4/10, 10/10	397,800	397,800	99,450	5,964,000
Series C - MTN	100,000,000	05/05/99	05/05/14	6.510%	4/10, 10/10	6,510,000	6,510,000	1,627,500	99,400,000
Series C - MTN	100,000,000	04/09/01	04/10/06	7.560%	4/10, 10/10	7,560,000	7,560,000	1,890,000	99,500,000
Series D - MTN	50,000,000	03/07/03	03/07/08	4.000%	3/7, 9/7	2,000,000	2,000,000	500,000	49,750,000
Series D - MTN	50,000,000	03/07/03	03/07/13	5.250%	3/7, 9/7	2,625,000	2,625,000	656,250	49,687,500
Series D - MTN	50,000,000	03/17/04	03/15/11	4.230%	3/15, 9/15	1,045,750	1,674,375	528,750	49,700,000
	415,000,000					24,116,817	24,729,913	6,296,800	412,628,000

Annualized weighted average interest rat 6.07%

HEI
LONG-TERM DEBT
September 2004

Description	09/30/04 Principal Balance	Date of Note	Maturity Date	Interest Rate	Payment Dates	Annual Interest Paid	Annual Accrued Interest	3Q04 Accrued Interest	Net Proceeds
Series B - MTN	30,000,000	12/05/95	12/05/05	6.660%	4/10, 10/10	1,998,000	1,998,000	499,500.00	29,812,500
Series B - MTN	10,000,000	02/14/96	02/14/06	6.545%	4/10, 10/10	654,500	654,500	163,625.00	9,937,500
Series B - MTN	7,000,000	10/01/97	10/01/12	7.130%	4/10, 10/10	499,100	499,100	124,775.00	6,951,000
Series B - MTN	5,000,000	10/1/97	10/01/07	6.930%	4/10, 10/10	346,500	346,500	86,625.00	4,968,750
Series B - MTN	5,000,000	10/1/97	10/01/07	6.900%	4/10, 10/10	345,000	345,000	86,250.00	4,968,750
Series B - MTN	1,000,000	10/02/97	10/04/04	6.800%	4/10, 10/10	66,867	51,378	17,000.00	994,000
Series B - MTN	1,000,000	10/6/97	10/06/05	6.830%	4/10, 10/10	68,300	68,300	17,075.00	994,000
Series B - MTN	6,000,000	06/09/98	06/15/05	6.630%	4/10, 10/10	397,800	397,800	99,450.00	5,964,000
[redacted]									
Series C - MTN	100,000,000	04/09/01	04/10/06	7.560%	4/10, 10/10	7,560,000	7,560,000	1,890,000.00	99,500,000
Series D - MTN	50,000,000	03/07/03	03/07/08	4.000%	3/7, 9/7	2,000,000	2,000,000	500,000.00	49,750,000
Series D - MTN	50,000,000	03/07/03	03/07/13	5.250%	3/7, 9/7	2,625,000	2,625,000	656,250.00	49,687,500
Series D - MTN	50,000,000	03/17/04	03/15/11	4.230%	3/15, 9/15	1,045,750	1,674,375	528,750.00	49,700,000
	415,000,000					24,116,817	24,729,953	6,296,800	412,628,000

HEI
LONG-TERM DEBT
December 2004

Description	12/31/04 Principal Balance	Principal O/S For 4Q04	Date of Note	Maturity Date	Interest Rate	Payment Dates	Annual Interest Paid	Annual Accrued Interest	4Q04 Accrued Interest	Net Proceeds
Series B - MTN	30,000,000	30,000,000	12/05/95	12/05/05	6.660%	4/10, 10/10	1,998,000	1,998,000	499,500	29,812,500
Series B - MTN	10,000,000	10,000,000	02/14/96	02/14/06	6.545%	4/10, 10/10	654,500	654,500	163,625	9,937,500
Series B - MTN	7,000,000	7,000,000	10/01/97	10/01/12	7.130%	4/10, 10/10	499,100	499,100	124,775	6,951,000
Series B - MTN	5,000,000	5,000,000	10/1/97	10/01/07	6.930%	4/10, 10/10	346,500	346,500	86,625	4,968,750
Series B - MTN	5,000,000	5,000,000	10/1/97	10/01/07	6.900%	4/10, 10/10	345,000	345,000	86,250	4,968,750
Series B - MTN	1,000,000	8,197	10/02/97	10/04/04	6.800%	4/10, 10/10	66,867	51,378	557	994,000
Series B - MTN	1,000,000	1,000,000	10/6/97	10/06/05	6.830%	4/10, 10/10	68,300	68,300	17,075	994,000
Series B - MTN	6,000,000	6,000,000	06/09/98	06/15/05	6.630%	4/10, 10/10	397,800	397,800	99,450	5,964,000
Series C - MTN	100,000,000	100,000,000	05/05/99	05/05/14	6.510%	4/10, 10/10	6,510,000	6,510,000	1,627,500	99,400,000
Series C - MTN	100,000,000	100,000,000	04/09/01	04/10/06	7.560%	4/10, 10/10	7,560,000	7,560,000	1,890,000	99,500,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/08	4.000%	3/7, 9/7	2,000,000	2,000,000	500,000	49,750,000
Series D - MTN	50,000,000	50,000,000	03/07/03	03/07/13	5.250%	3/7, 9/7	2,625,000	2,625,000	656,250	49,687,500
Series D - MTN	50,000,000	50,000,000	03/17/04	03/15/11	4.230%	3/15, 9/15	1,045,750	1,674,375	528,750	49,700,000
	415,000,000	414,008,197					24,116,817	24,729,953	6,280,357	412,628,000

Annualized weighted average interest rate 6.07%

DOD/HECO-IR-3-3

Please provide the 2004 S.E.C. Form 10-K as soon as it is available and any 10-Qs and 8-Ks issued by Hawaiian Electric Industries, Inc. since January 1, 2004.

HECO Response:

This information has been routinely filed with the Public Utilities Commission of the State of Hawaii and with the Consumer Advocate and is a matter of public record. The information is voluminous. These reports can be found on the HEI internet site under SEC filings at

DOD/HECO-IR-3-4

Please provide Hawaiian Electric Industries' most recent Annual Report to Shareholders (as well as any statistical supplements available to investors). Also, if Hawaiian Electric Company provides a separate Annual Report, please provide that document as well.

HECO Response:

Hawaiian Electric Industries' 2004 Annual Report to Shareholders and Appendix A to the 2004 Annual Report to Shareholders was filed on April 5, 2005 with the Public Utilities Commission of the State of Hawaii, and with the Consumer Advocate, and is a matter of public record. This information as well as HEI's 2004 Statistical Supplement and Utility Forecast are voluminous. These reports can be found on the HEI internet site under Investor Relations, Financial Information at http://www.hei.com/.

Hawaiian Electric Company, Inc. does not have a separate 2004 Annual Report.

DOD/HECO-IR-3-5

Please provide a copy of the most recent bond rating agency (Standard & Poor's, Moody's, Fitch) report for Hawaiian Electric Industries, Inc. and separately, if available, for Hawaiian Electric Company.

[Note: Report provided should be most recent complete multi-page in-depth report, not a one or two-page update.]

HECO Response:

See the attached and the response to CA-IR-102.

Note: The attached information is copyrighted. The copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the attachment are subject to the copyright laws.

Moody's Investors Service

Credit Opinion
30 DEC 2004

Credit Opinion: Hawaiian Electric Company, Inc.

Hawaiian Electric Company, Inc.

Honolulu, Hawaii, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
Preferred Stock	Baa3
Bkd Commercial Paper	P-2
Parent: Hawaiian Electric Industries, Inc.	
Outlook	Stable
Senior Unsecured	Baa2
Bkd Commercial Paper	P-2

Contacts

Analyst	Phone
A.J. Sabatelle/New York	1.212.553.1653
Laura Schumacher/New York	
Daniel Gates/New York	

Key Indicators

Hawaiian Electric Company, Inc.

	3Q04 LTM	2003	2002	2001
Adjusted Funds from Operations / Adjusted Debt [1][2]	21.0%	22.0%	22.3%	21.2%
Retained Cash Flow / Adjusted Debt [2]	18.1%	15.5%	17.3%	16.9%
Common Dividends / Net Income Available for Common	29.8%	73.1%	48.9%	41.1%
Funds from Operations - Capitalized Interest + Adjusted Interest / Adjusted Interest [1][3]	4.77	4.55	4.58	4.08
Adjusted Debt / Adjusted Capitalization [2][4]	47.6%	47.3%	47.6%	47.8%
Net Income Available for Common / Common Equity	9.0%	8.4%	9.8%	10.1%

[1] Preferred dividends have been deducted from FFO [2] Adjusted debt includes quarterly income preferred securities (QUIPS) [3] Interest is adjusted to include preferred dividends [4] Adjusted capitalization reflects the adjustments made to debt

The company's emphasis on relationship building particularly with the large customer segment such as the military.

A stable regulatory environment that emphasizes traditional cost of service techniques.

Strong cash flows and a manageable level of capital expenditures.

Credit Challenges

Credit challenges facing HECO include:

The cash flow volatility that is associated with an economic base that has a significant reliance on tourism for incremental growth.

A strong environmental lobby that not only extends the time frames over which large scale construction projects can be completed but leads to increased costs.

The growth in distributed generation alternatives increases the competitive environment particularly for large, geographically concentrated customers, such as hotels.

The potential for the company's parent, Hawaiian Electric Industries (HEI: Baa2 Senior Unsecured Debt; Stable Outlook), to reconsider diversification opportunities outside of the existing portfolio along with the potential for matieral changes to HECO's dividend requirement.

Rating Rationale

Hawaiian Electric Company's (HECO) Baa1 senior unsecured rating reflects the evolution of the major competitive threats to the company's business and the generally supportive regulatory environment it works to maintain. The rating also considers the company's high electric rates due to the environmental challenges of construction and operations in Hawaii as well as the rising cost of imported fuel.

Although the Hawaiian Islands' geographic isolation provides a barrier to entry for mainland utilities, HECO does face competition from independent power producers and self-generation, particularly for large customers. To date, HECO has sought to offset the financial impact of competition by working closely with its major customers, such as the US military, as the end-user seeks to reduce overall energy costs.

While impacted by world events of the past few years, economic conditions in the Hawaiian Islands have generally stabilized. As a result, so has the company's financial performance. Importantly, the company's financial profile reflects a strong commitment to cost control and productivity enhancements. We expect that as growth accelerates, HECO will need to add generation and transmission facilities to meet demand and to prepare for future needs. Management expects to finance their 5-year capital plan largely with internally generated cash flow.

Rating Outlook

HECO's stable rating outlook reflects the expectation that over the longer-term, improved fundamentals due to strong operating performance, favorable economic conditions, and the parent's reduced emphasis on overseas investments will sustain the company's credit profile.

What Could Change the Rating - UP

A series of regulatory decisions that result in substantially improved credit metrics coupled with a continuation of a generally improving local economy.

What Could Change the Rating - DOWN

Weaker than expected regulatory support causing both earnings and sustainable cash flow to suffer.

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Research:

Summary: Hawaiian Electric Company, Inc.

Publication date: 13-Dec-2004
Primary Credit Analyst(s): Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Credit Rating: BBB+/Stable/A-2

Rationale

The ratings on Hawaiian Electric Co. Inc. are based on the consolidated credit profile of its parent, Hawaiian Electric Industries Inc. (HEI), which includes Hawaiian Electric's electric utility operations and its two island utility subsidiaries (78% of core revenues and 66% of operating income in 2003) and the riskier financial services operations of HEI subsidiary, American Savings Bank FSB, which contributed 21% of core revenues and 34% of operating income in 2003. The ratings on HEI reflect an average business profile and somewhat weak, but gradually improving, financial measures.

Hawaiian Electric's average business position is a function of limited competitive threats because of the utility's geographic isolation, nominal stranded-asset risk, and a generally supportive regulatory environment with an excellent fuel clause. These strengths are tempered by Hawaii's tourism-driven economy, heavy revenue dependence on the military, high electric rates, significant reliance on fuel oil, and large purchased-power obligations. Hawaiian Electric is spared the competitive threat of wholesale approaching 22% in nearby years owing to tight cost controls, rate relief, and the impact on the company's earnings from continued expansion of Hawaii's economy.

Importantly, a responsive rate order from the Hawaii Public Utilities Commission with regard to Hawaiian Electric's pending rate case for a $98.6 million (9.9%) rate hike would help lift the company's key financial measures to more appropriate levels for current ratings. Although there are no time restrictions for the commission to issue a final order, an interim decision is required within 10 months after the rate case application is filed, if an evidentiary hearing is held or after 11 months, if an evidentiary hearing has not been completed. This would mean a possible interim decision by the fourth quarter of 2005. Rate relief is needed to recover the costs of reliability investments made since 1995, which include a number of transmission upgrades, the costs associated with a purchased-power contract, a new fuel oil pipeline, and costs to ensure the continuation and expansion of energy efficiency and conservation programs.

Hawaiian Electric's balance sheet is stronger than HEI's with total debt to total capital at about 51% at Sept. 30, 2004, including Hawaiian Electric's hybrid preferred securities and purchased-power contracts. Although the utility's adjusted FFO interest coverage is suitable for current ratings at about 4.0x, FFO to total debt is weak at 21.4%, as of Sept. 30, 2004. In March 2004, HECO Capital Trust III issued $50 million in preferred securities, guaranteed by Hawaiian Electric, and loaned the proceeds to Hawaiian Electric. These proceeds, as well as short-term loans from HEI's and Hawaiian Electric's issuance of commercial paper, were used to redeem $100 million in preferred securities issued by HECO Capital Trust I and II (and guaranteed by Hawaiian Electric), which should help to further strengthen Hawaiian Electric's balance sheet. Standard & Poor's anticipates that Hawaiian Electric will repay the short-term loans from HEI by the end of 2004 primarily with funds saved from reducing dividends to HEI in 2004.

Short-term credit factors.

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2', incorporating strong liquidity and the ability to internally fund dividends and capital expenditure requirements. HEI faces a manageable maturity schedule, with only $1 million maturing in 2004 and $37 million maturing throughout 2005. Hawaiian Electric has no maturing long-term debt until 2012. At Sept. 30, 2004, HEI had $13 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents). HEI and Hawaiian Electric had bank lines totaling $80 million and $90 million, respectively, at the end of September 2004. Of HEI's facilities, $10 million matured in October 2004, $20 million in April 2005, and $30 million in June 2005. The company renewed its $10 million line of credit maturing in October 2004 and increased it to $15 million. Earlier this month, the company also renewed its $20 million line of credit maturing in December 2004 and increased it to $30 million. Also in December, the line of credit maturing in June 2005 was reduced to $15 million. Of Hawaiian Electric's facilities, $50 million matures in April 2005, $10 million in May 2005, and $30 million in June 2005. At the end of September 2004, the lines were undrawn.

Covenants in HEI's and Hawaiian Electric's lines require Hawaiian Electric to maintain a consolidated capitalization ratio (exclusive of short-term debt) of at least 35%. At Sept. 30, 2004, Hawaiian Electric's consolidated common equity to capitalization ratio was 55%. Certain HEI lines of credit totaling $20 million and $30 million require the company to maintain a consolidated net worth, exclusive of intangible assets, of at least $900 million and $850 million, respectively, which at the end of September 2004 was $1.1 billion. The covenants for the line of credit agreements do not contain interest coverage ratio requirements. None of HEI's or Hawaiian Electric's lines contains material adverse change clauses or rating triggers that affect access to the lines of credit.

In 2003, HEI's net cash flow of about $193 million (after dividends of $75 million) covered HEI's $163 million construction program. Consolidated capital outlays are projected to hover around $213 million in 2004 and decline to $180 million in 2005. The higher expenditures are primarily for generation projects. However, the bulk of the construction program should continue to be funded internally. Importantly, ongoing modest growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows and the bank to maintain normal cash dividend levels (50% of its earnings) while still supporting its own business growth.

HEI has $150 million of debt capacity remaining under a Rule 415 shelf registration. As of Sept. 30, 2004, proceeds of approximately $13 million from a previous sale of special purpose revenue bonds issued by the State of Hawaii's Department of Budget and Finance for the benefit of Hawaiian

Electric remained undrawn.

■ Outlook

The stable outlook on Hawaiian Electric mirrors that of parent HEI and reflects limited competitive pressures, aggressive cost containment, steady banking operations, strong liquidity, and expectations for gradual financial improvement. The economy continues to grow due to strength in nontourism sectors, but may be affected by external conditions, such as the global economy and the threat of terrorist events in the U.S.

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Research:

Research Update: Hawaiian Electric Industries And Utility Units Ratings Affirmed; Outlook Revised To Negative

Publication date: 22-Apr-2005
Primary Credit Analyst(s): Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Credit Rating: BBB/Negative/A-2

Rationale

On April 22, 2005, Standard & Poor's Ratings Services affirmed its 'BBB' corporate credit rating on Hawaiian Electric Industries Inc. (HEI) and its 'BBB+' corporate credit ratings on subsidiary Hawaiian Electric Co. Inc. and its units, Hawaii Electric Light Co. Inc. and Maui Electric Co. Ltd. At the same time, Standard & Poor's revised its outlook on the companies to negative from stable.

The outlook revision reflects a declining trend in HEI's consolidated financial condition, despite the strong Hawaii economy and the company's efforts in recent years to strengthen capital structure balance. The company's financial metrics have been pressured owing to rising operating expenses, yet to be recovered investments, and the long-term lack of rate relief. Absent a supportive rate decision in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate for the current ratings.

The ratings on HEI are based on the consolidated credit profile of HEI's family of companies, which include the regulated electric utility Hawaiian Electric and its two utility subsidiaries (81% of core revenues and 64% of operating income as of Dec. 31, 2004) and the riskier financial services operations of subsidiary American Savings Bank FSB, which contributed 19% of core revenues and 39% of operating income as of Dec. 31, 2004.

HEI has a satisfactory business profile and weak financial measures. The company's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, modest rate-relief needs, an excellent fuel clause, and steady banking operations. American Savings Bank's consistent earnings are driven

Internal cash covered about 70% of HEI's capital program in 2004.
[illegible] no new capacity additions (which may eventually be necessary to

$12 million from a previous sale of special purpose revenue bonds issued by the State of Hawaii's Department of Budget and Finance for the benefit of Hawaiian Electric remained undrawn.

Outlook

The negative outlook reflects HEI's declining financial trend. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaii economy, a punitive rate order, and/or an erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit supportive actions by the company as well as responsive rate treatment that would enable the company to produce FFO to total debt in the lower to mid-20s percentage range would lead to ratings stability.

Ratings List

	To	From
Hawaiian Electric Industries Inc.		
Corporate credit rating	BBB/Negative/A-2	BBB/Stable/A-2
Senior unsecured debt	BBB	
Preferred Stock	BB+	
Commercial paper	A-2	
Hawaiian Electric Co. Inc.		
Corporate credit rating	BBB+/Negative/A-2	BBB+/Stable/A-2
Senior unsecured debt	BBB+	
Preferred stock	BBB-	
Commercial paper	A-2	
Maui Electric Co. Ltd.		
Corporate credit rating	BBB+/Negative/--	BBB+/Stable/--
Senior unsecured debt	BBB+	
Hawaii Electric Light Co. Inc.		
Corporate credit rating	BBB+/Negative/--	BBB+/Stable/--
Senior unsecured debt	BBB+	

Complete ratings information is available to subscribers of RatingsDirect,

DOD/HECO-IR-3-6

a) Please provide the monthly short-term debt balances for Hawaiian Electric Industries, Inc. and Hawaii Electric Company for each month from January 2002 through the most recent month available. Please explain how the monthly short-term debt balance is calculated (e.g., month-ending balance, average daily balance), and provide a sample calculation.

b) Please provide, for each month, the monthly cost-rate of that short-term debt for Hawaiian Electric Industries and separately for Hawaiian Electric Company, and a sample calculation showing how that monthly cost rate is derived.

c) Please provide a narrative description of Hawaiian Electric Industries' short-term debt financing arrangements, as well as inter-company borrowing arrangements between Hawaiian Electric Industries subsidiaries.

HECO Response:

a) Please see schedule on pages 3 - 4. The monthly short-term balances are based on month-ending balances. HECO (Oahu only) short-term borrowings shown on page 3 are comprised of commercial paper issuances (net of discount, if any) plus intercompany borrowings from HEI and MECO, net of advances to HELCO. HEI (parent company only) short-term borrowings shown on page 4 are comprised of commercial paper issuances. HEI short-term borrowings for financial statement purposes (as shown in response to DOD/HECO-IR-3-1, for example) are the consolidation of HECO short-term borrowings (net of any intercompany borrowings) and HEI (parent company only) short-term borrowings.

b) HECO and HEI do not calculate the embedded cost of short-term debt. See discussion in response to DOD-IR-3-2(c).

c) HEI can negotiate, execute and deliver short-term borrowings, including the sale of commercial paper, drawings under bank lines of credit and the arrangement of corporate

[illegible]

The objective of intercompany borrowing and investment is to make efficient use of funds available from affiliated companies while meeting the cash needs of the companies. When subsidiaries need funds, HEI will loan excess cash to its subsidiaries or may borrow from external sources to meet subsidiary cash needs. In managing its cash requirements, HECO may borrow from HEI. If HECO borrows from HEI, HECO is charged HEI's effective weighted-average short-term external borrowing rate, plus the borrowing and transaction processing costs, provided HEI's commercial paper rating is equal to or better than HECO's commercial paper rating. Currently, HECO and HEI have the same commercial paper rating. In the event HEI's commercial paper rating falls below HECO's, interest on loans to HECO shall be charged at HECO's weighted-average short-term external borrowing rate. If HEI has no external borrowings and its commercial paper rating is equal to or better than HECO's commercial paper rating, HECO is charged the average of the effective rate for 30-day dealer-placed commercial paper quoted by the Wall Street Journal on each Friday during the month, plus fifteen basis points (.15%).

HECO may loan funds to HEI with prior PUC approval. However, it is HECO's policy to not loan funds to HEI.

HECO Short-Term Debt
Month-End Balances
($ in thousands)

	2005	2004	2003	2002
Jan	73,957	14,700	4,400	32,297
Feb	85,852	42,537	34,990	49,788
Mar	79,520	41,492	30,300	46,226
Apr	88,563	63,302	31,730	51,403
May		58,492	20,000	36,628
Jun		63,513	17,400	50,819
Jul		50,902	11,700	40,573
Aug		36,717	16,500	25,994
Sep		51,972	18,500	43,428
Oct		57,828	25,000	18,400
Nov		56,698	24,000	14,500
Dec		61,460	20,700	13,700

HEI Short-Term Debt
Month-End Balances
($ in thousands)

	2005	2004	2003	2002
Jan	-	-	-	-
Feb	-	-	-	-
Mar	-	-	-	-
Apr	-	-	-	-
May		-	-	-
Jun		-	-	4,600
Jul		-	-	-
Aug		-	-	935
Sep		-	-	-
Oct		-	-	-
Nov		-	-	-
Dec		-	-	-

DOD/HECO-IR-3-7

Please provide an income statement, balance sheet and cash flow statement for Hawaiian Electric Company at the end of each fiscal year over the past ten years.

HECO Response:

The requested information has been routinely filed annually with its annual reports with the Public Utilities Commission of the State of Hawaii, and with the Consumer Advocate, and is a matter of public record. The information may also be reviewed at HECO's office. Please call Irene Sekiya at 543-4778 to arrange to review this information.

DOD-IR-3-8

Please provide a description of Hawaiian Electric Company's ten largest industrial and commercial customers (name of customer can be withheld), and indicate what percentage of the Company's total 2002 and 2003 kWh amount and revenues each represents. Also, please provide copies of any inter-company reports analyzing the potential of any of the listed companies to self-generate, and outlining how the Company would respond.

HECO Response

The following is a table of HECO's top 10 commercial and industrial customers for 2002 and [redacted]

HECO prepared an updated forecast for its IRP-3 process in June 2004, which took into account delays in implementing the CHP Program (due to its suspension) and certain larger potential projects outside the scope of the proposed program of which it was aware. Since the IRP-3 forecast was prepared, however, a number of events occurred reflecting the high degree of uncertainty in forecasting the CHP market, whether it is for HECO CHP projects or non-utility CHP projects. An updated CHP forecast was developed in early February 2005 that reflected these events, however, subsequent to this forecast the Pacific Allied CHP Agreement was terminated by the customer. A revised forecast that takes the Pacific Allied termination into account was developed, and this March 2005 forecast served as the basis for HECO's CHP capacity assumptions in its 2005 HECO Adequacy of Supply report, filed March 10, 2005. HECO plans to file with the Commission its IRP-3 report, which includes its assessment of DG and CHP resources, by October 31, 2005. The draft of the report sent to HECO's Advisory Group is available on HECO's website at www.heco.com, within the Renewable Energy – Integrated Resource Planning section.

In the DG Investigation, Docket No. 03-0371, HECO provided extensive information (i.e., testimonies, exhibits, workpapers and briefs) on DG and CHP, including its assessment of the CHP market, and this information is a matter of public record. The information that was provided by HECO in Docket No. 03-0371 has been filed with the Commission, and the Consumer Advocate was a party to the proceeding, and the information is voluminous. HECO can make available to the Department of Defense a copy of the information filed in Docket No. 03-0371. Please contact Dan Brown with HECO's Regulatory Affairs Division at 543-4795 to make arrangements.

With respect to the ten customers listed in the table above, these large customers were included, with other large customers with a demand greater than 400 kW, in HECO's assessment of the CHP market potential on Oahu. (See HECO T-1, pages 21-24, Docket No. 03-0371.) However, a CHP project analysis was performed only for customer number 10 listed in the table above., and this CHP project has been deferred indefinitely by the mutual agreement of HECO and the customer. HECO objects to the production of the CHP project analysis containing customer-specific information for customer number 10 on the grounds that (1) such information is confidential and has been protected from disclosure by the Commission in other proceedings, and (2) the disclosure of such information has not been consented to by the customer. HECO is willing to provide the CHP project analysis for customer 10 available to the Commission and Consumer Advocate under an appropriate protective order, but objects to providing such information to the DOD for the reasons provided above.

Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

December 17, 2003

William A. Bonnet
Vice President
Government and Community Affairs

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
465 South King Street
Kekuanaoa Building, 1st Floor
Honolulu, Hawaii 96813

FILE
2003 DEC 17 P 54
PUBLIC UTIL
COMMISSI

Dear Commissioners:

Subject: Docket No. 03-0366 - HECO/HELCO/MECO
<u>CHP Program and Schedule CHP</u>

HECO, HELCO and MECO ("the Companies") have discovered computational errors in the "Total" line item that was included in Exhibit A in the Companies' CHP Program and Schedule CHP application, filed on October 10, 2003. Attached is a revised Exhibit A of the application. The economic analyses included in the CHP Program and Schedule CHP application used the correct "Total" amounts, and no revisions are necessary.

If you have any questions on this matter, please contact Dan Brown at 543-4795.

Sincerely,

William A. Bonnet

Attachment

cc: Division of Consumer Advocacy

EXHIBIT A
PAGE 1 OF 6

REVISED 12-17-03

pdgfcst 8-20-03.xls
9/25/2003

HECO CHP Forecast - With Utility Participation
Total Market Annual Potential

	Total kW[1]	Systems	Utility		3rd Party	
			Systems	kW	Systems	kW
2003	300	1	1	300	0	0
2004	2730	6	5	2275	1	455
2005	3000	6	5	2500	1	500
2006	4000	8	6	3000	2	1000
2007	4000	8	6	3000	2	1000
2008	4500	9	7	3500	2	1000
2009	3500	7	6	3000	1	500
2010	3000	6	5	2500	1	500
2011	2500	5	4	2000	1	500
2012	2000	4	3	1500	1	500
2013	2000	4	3	1500	1	500
2014	1500	3	2	1000	1	500
2015	1500	3	2	1000	1	500
2016	1500	3	2	1000	1	500
2017	1350	3	2	900	1	450
2018	1350	3	2	900	1	450
2019	1000	3	2	667	1	333
2020	867	3	2	667	1	200
2021	666	2	1	333	1	333
2022	867	3	2	667	1	200
Total	42130 ~~44329~~	90 ~~97~~	68 ~~72~~	32209 ~~33542~~	22 ~~25~~	9921 ~~10787~~
[illegible]	18530	38	30	14575	8	3955

EXHIBIT A
PAGE 2 OF 6
REVISED 12-17-03

pdgfcst 8-20-03.xls
9/25/2003

HECO CHP Forecast
No Utility Participation
Total Market Annual Potential

	Total kW[1]	Systems	kW/Unit
2003	300	1	300
2004	1000	3	333
2005	1500	2	750
2006	1500	3	500
2007	1500	3	500
2008	1500	3	500
2009	1500	3	500
2010	1500	3	500
2011	1000	2	500
2012	1000	2	500
2013	1000	2	500
2014	1000	2	500
2015	1000	2	500
2016	1000	3	333
2017	1000	3	333
2018	1000	3	333
2019	1000	3	333
2020	666	2	333
2021	666	2	333
2022	666	2	333
	21298	49	
Total	~~23296~~	~~55~~	
2003-08	7300	15	

[1] 3rd party CHP only, no utility CHP
Source: Energy Projects, 7/16/03

hdgfcst 8-20-03.xls
9/25/2003

EXHIBIT A
PAGE 3 OF 6

REVISED 12-17-03

HELCO CHP Forecast - With Utility Participation
Total Market Annual Potential

	Total kW [1]	Systems	Utility		3rd Party	
			Systems	kW	Systems	kW
2003	900	2	0	0	2	900
2004	1600	4	3	1200	1	400
2005	2400	4	3	1800	1	600
2006	2500	5	4	2000	1	500
2007	2500	5	4	2000	1	500
2008	2500	5	4	2000	1	500
2009	2000	5	4	1600	1	400
2010	2000	5	4	1600	1	400
2011	1500	4	3	1200	1	300
2012	1200	4	3	900	1	300
2013	1000	4	3	750	1	250
2014	1000	4	3	750	1	250
2015	1000	4	3	750	1	250
2016	900	4	3	750	1	150
2017	950	4	3	750	1	200
2018	850	4	3	750	1	100
2019	1000	4	3	750	1	250
2020	900	4	3	750	1	150
2022	950	4	3	750	1	200
Total	28250 ~~30500~~	82 ~~92~~	61 ~~68~~	21550 ~~23300~~	21 ~~24~~	6700 ~~7200~~
2003-08	12400	25	18	9000	7	3400

[1] Includes utility and 3rd party CHP
Source: Energy Projects, 7/25/03

REVISED 12-17-03

hdgfcst 8-20-03.xls
9/25/2003

HELCO CHP Forecast
No Utility Participation
Total Market Annual Potential

	Total kW [1]	Systems	kW/Unit
2003	900	2	450
2004	1200	3	400
2005	1400	4	350
2006	1200	3	400
2007	1000	3	333
2008	1000	3	333
2009	1000	3	333
2010	1000	3	333
2011	1000	4	250
2012	1000	4	250
2013	1000	4	250
2014	1000	4	250
2015	1000	4	250
2016	1000	4	250
2017	1000	4	250
2018	1000	4	250
2019	1000	4	250
2020	750	3	250
2021	750	3	250
2022	750	3	250
Total	19950 ~~22200~~	69 ~~78~~	
2003-08	6700	18	
2003-12	10700	32	

[1] 3rd party CHP only, no utility CHP
Source: Energy Projects, 7/16/03 CHP Forecast - No Utility Participation

REVISED 12-17-03

mdgfcst 6-20-03.xls
9/25/2003

Maui CHP Forecast - With Utility Participation
Total Market Annual Potential

	Total kW[1]	Total Systems	Utility Systems	Utility kW	3rd Party Systems	3rd Party kW
2003	1500	2	1	1000	1	500
2004	3000	6	5	2500	1	500
2005	3150	7	6	3000	1	150
2006	4000	8	7	3500	1	500
2007	2700	7	6	2400	1	300
2008	1100	4	3	1000	1	100
2009	1150	5	4	1000	1	150
2010	1000	5	4	800	1	200
2011	900	4	3	800	1	100
2012	950	4	3	800	1	150
2013	700	3	2	500	1	200
2014	850	4	3	750	1	100
2015	950	4	3	750	1	200
2016	850	4	3	750	1	100
2017	900	3	2	500	1	400
2018	900	4	3	750	1	150
2019	950	4	3	750	1	200
2020	600	3	2	500	1	100
2021	900	4	3	750	1	150
2022	700	3	2	500	1	200
Total	27750 ~~30350~~	88 ~~99~~	68 ~~76~~	23300 ~~25300~~	20 ~~23~~	4450 ~~5050~~
2003-08	15450	34	28	13400	6	2050

[1] Includes utility and 3rd party CHP
Source: Energy Projects, 7/16/03 CHP Forecast - With Utility Participation

REVISED 12-17-03

mdgfcst 8-20-03.xls
9/25/2003

Maui CHP Forecast
No Utility Participation
Total Market Annual Potential

	Total kW[1]	Systems	kW/Unit
2003	1200	2	600
2004	1200	3	400
2005	1300	3	433
2006	1000	3	333
2007	1000	3	333
2008	1000	3	333
2009	1000	4	250
2010	1000	5	200
2011	800	3	267
2012	800	3	267
2013	400	1	400
2014	400	2	200
2015	400	2	200
2016	400	2	200
2017	400	1	400
2018	400	2	200
2019	400	2	200
2020	200	2	100
2021	200	1	200
2022	150	1	150
Total	13650 ~~14250~~	48 ~~51~~	
2003-08	6700	17	

[1] 3rd party CHP only, no utility CHP
Source: Energy Projects, 7/16/03 CHP Forecast - No Utility Participation

DOD/HECO-IR-3-9

Please provide a copy of the Company's (HECO's) most recent five-year financial forecast (or most similar document).

<u>HECO Response:</u>

The requested information is provided on page 2.

FORECAST: 2005 - 2009

Hawaiian Electric Company, Inc. Years ended December 31 (dollars in millions)	2005	2006	2007	2008	2009
USES OF CAPITAL					
Capital expenditures	123.7	113.3	101.3	140.4	96.4
Less:					
AFUDC	7.4	6.6	4.2	9.2	6.9
Contributions in aid of construction	20.3	21.1	8.5	7.7	4.5
Net captial expenditures	96.0	85.6	88.6	123.5	85.0
Other requirements	-	-	-	-	-
Total net requirements	$ 96.0	$ 85.6	$ 88.6	$ 123.5	$85.0
SOURCES OF CAPITAL					
Internal funds					
Depreciation and amortization	$ 72.8	$ 77.4	$ 81.8	$ 84.7	$85.2
Deferred income taxes and tax credits, net	(2.0)	(5.2)	(0.7)	0.3	2.8
Retained earnings and other, excluding AFUDC	(2.3)	39.1	1.6	14.6	(2.0)
Total internal sources, excluding AFUDC	68.5	111.3	82.7	99.6	86.0
External financing sources - total debt	27.5	(25.7)	5.9	23.9	(1.0)
Total sources	$ 96.0	$ 85.6	$ 88.6	$ 123.5	$85.0

DOD/HECO-IR-3-10

Please provide a complete, detailed copy of Hawaiian Electric Industries' most recent bond rating agency presentation (i.e., not a slide – show summary, but the volume that discusses the Company's operations, generation, purchased power contracts, financial projections and service territory economics in detail.)

HECO Response:

[redacted]

and/or the New York Stock Exchange that information that would be meaningful to an investor (such as earnings estimates) be released to all investors, if the information is disclosed beyond a limited number of "insiders". Forecasts of earnings, etc. are the types of information that, if selectively released, could violate such requirements.

Further, information in presentations to rating agencies related to HEI and its non-utility subsidiaries is not relevant to the issues in this docket. The information related to HEI's non-utility subsidiaries is clearly irrelevant. While HEI is the parent of HECO, the Commission generally has ruled that HEI, as a diversified holding company, is not an approximate proxy for HECO or its utility subsidiaries in determining their costs of capital. (See Decision and Order No. 11317 in Docket No. 6531 (HECO rate proceeding) and Decision and Order No. 10993 in Docket No. 6432 (HELCO rate proceeding).)

DOD/HECO-IR-3-11

Are there any debt issues that appear on the balance sheet of Hawaiian Electric Company that support the Company's investment in non-utility property, subsidiary companies or other investments? If so, please identify the type and amount of those debt issues; if not, please explain why not.

HECO Response:

There are no debt issues on the balance sheet of HECO (Oahu) supporting investment in non-utility property, subsidiary companies or other investments.

DOD/HECO-IR-3-12

Please provide a copy of HECO's FERC Form 1 for 2004, as soon as it becomes available.

<u>HECO Response:</u>

A copy of HECO's FERC Form No. 1 for the year 2004 will be provided after it has been completed and filed with the FERC, which filing is scheduled to occur on or about April 25, 2005.

DOD/HECO-IR-3-13

a. Please provide a complete copy of one electric utility cost of capital testimony (Direct, Rebuttal and Rejoinder, if applicable) filed by Dr. Morin in 2000 or 2001.

b. Please provide a complete copy of one electric utility cost of capital testimony (Direct, Rebuttal and Rejoinder, if applicable) filed by Dr. Morin in the 1995-1997 period.

Dr. Morin's Response:

a. Enclosed is a direct testimony. Dr. Morin does not keep historical records of rebuttal testimonies in his archives. Old testimonies are presumably available in public records and/or in the Lexis data base.

b. Dr. Morin does not keep historical records of past rate of return testimonies in his archives extending as far back as 1995-97. Old testimonies are presumably available in public records and/or in the Lexis data base.

STATE OF IOWA
DEPARTMENT OF COMMERCE
BEFORE THE IOWA STATE UTILITIES BOARD

IN RE: **APPLICATION OF MIDAMERICAN ENERGY COMPANY FOR A DETERMINATION OF RATEMAKING PRINCIPLES**	**DOCKET NO. RPU-01-__**

DIRECT TESTIMONY
OF
DR. ROGER A. MORIN

INTRODUCTION

Q. Please state your name, address, and occupation.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry also at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. Please describe your educational background.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. Please summarize your academic and business career.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet where I conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty years, I have conducted numerous national seminars on such topics as "Utility Finance", "Utility Cost of Capital", "Alternative Regulatory Frameworks," and on "Utility Capital Allocation" which I have developed on behalf of The Management Exchange Inc. in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va. 1984. My more recent book, Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities, was released by the same publisher in late 1994. I have engaged in extensive consulting activities on behalf of numerous corporations and legal firms in matters of financial management and corporate litigation. Exhibit RAM-1 describes my professional credentials in more detail.

Q. Have you testified on cost of capital before?

A. Yes, I have been a cost of capital witness before more than 40 regulatory boards in North America, including the Iowa Utilities Board ("IUB" or the "Board"), the Federal Energy Regulatory Commission, and the Federal Communications Commission. I have appeared before the following state and provincial commissions:

Alabama	Illinois	New Brunswick	Pennsylvania
Alaska	Indiana	New Jersey	Quebec
Alberta	Iowa	New York	South Carolina
Arizona	Louisiana	Newfoundland	Tennessee
British Columbia	Manitoba	North Carolina	Texas
California	Michigan	North Dakota	Utah
Colorado	Minnesota	Ohio	Vermont
Florida	Mississippi	Oklahoma	Washington
Georgia	Montana	Ontario	West Virginia
Hawaii	Nevada	Oregon	

The details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

Q. Please describe the purpose of your testimony.

A. MidAmerican Energy Company's ("MidAmerican" or the "Company") is requesting that the rate of return on common equity to fairly compensate the Company's shareholders for the risk of the Greater Des Moines Energy Center ("GDMEC") electricity generation operations in the state of Iowa be set at 13.25%. I have been asked to provide support for that estimate.

Q. Would you please briefly identify the exhibits and appendix that accompany your testimony?

A. Yes. I have attached to my testimony Exhibits RAM-1 through RAM-8 and Appendices A and B. These Exhibits and Appendices relate directly to points in my testimony, and are described in further detail in connection with those points.

Q. Please summarize your findings.

A. The return on equity required on the Company's investment in the GDMEC cannot be observed directly. It must be developed by analyzing information about capital market conditions, with reference to the conditions of the particular utility or line of business to which the required return on equity pertains. My analysis shows that a 13.25% return on equity is appropriate, and indeed very conservative, for the Company's investment in the GDMEC.

Of the various methodologies that are available to estimate the return on equity, I have selected the Capital Asset Pricing Model ("CAPM") and Discounted Cash Flow ("DCF") methodologies. Both of these models are widely used to estimate the return on equity, and both have been used for that purpose before the Board. I have calculated return on equity estimates for four industries that are comparable to the Company's power generation business: wholesale power generators, oil and gas companies, telecommunications companies, and diversified natural gas companies. Oil and gas, telecommunications, and natural gas companies are comparable to wholesale electricity generation and the Company's generation assets for at least two reasons. First, these are highly capital-intensive. Second, a significant portion of the output of these industries can be characterized as commodities and the output of one company is generally indistinguishable from the output of another, so that price is the main basis of sales.

My results clearly demonstrate that the required return on equity for the Company's investment in the GDMEC falls within the range of 14.0% to 15.0%. Inasmuch as the 13.25% return on equity lies slightly below this range, the 13.25% return on equity should be found reasonable by the Board, and is in fact a concession by the Company to its ratepayers.

Q. Please describe how your testimony is organized.

A. The remainder of my testimony is organized into four sections, the first addresses the fundamentals of investment risk, the second deals with the application of the CAPM and the third discusses the application of the DCF model. The final section summarizes my findings.

INVESTMENT RISK

Q. Please discuss the notion of investment risk.

A. The two major components of investment risk are business and financial risk.

TOTAL RISK = BUSINESS RISK + FINANCIAL RISK

Business risk encompasses all the operating factors, which collectively increase the probability that expected future income flows accruing to investors may not be realized, because of the fundamental nature of the firm's business. Business risk is due to sales volatility and operating leverage. Sales volatility refers to the uncertainty in the demand for the firm's products (demand risk) due in part to external non-controllable factors, such as the basic cyclicality of the firm's products, the products' income and price elasticities, the amount of competition, the availability of product substitutes, the risk of technological obsolescence, the degree of regulation (regulatory risk), and the conditions of the labor and raw materials markets.

The business risk of utilities is assessed by examining the strength of long-term demand for utility products and services. The size and growth rate of the market, the diversity of customer base and its economic solidity, the availability of substitutes and degree of competition, the utility's relative competitive standing in its major markets, including residential, industrial and commercial markets, all impact business risk.

Earnings volatility is also related to internal or controllable factors. The reactions of a firm's management to the business environment, such as the adoption of a particular cost structure, are important dimensions of business risk. If all production costs are variable, then operating income varies proportionately to sales variability. As is the case for utilities, a large portion of costs are fixed; thus, operating income is far more volatile than sales. This magnification effect of fixed costs on the variability of operating income is referred to as "operating leverage".

Operating efficiency from the standpoint of cost and quality of service is another factor which may influence a utility's competitive risk exposure. Other examples of internal risk factors include the degree of diversification in the firm's asset structure, managerial efficiency, growth strategy, research and development policies, and competitive posture.

The size of a utility's construction program is an important source of business risk, to the extent that new construction is to meet projected demand, and that the latter is more difficult to forecast than existing demand. This forecasting risk is compounded by regulatory lag and attrition.

An important component of business risk for utilities is "regulatory risk". Regulation can compound the business risk premium if it is unpredictable in reacting to rate hike requests both in terms of the time lag of its response and its magnitude. For example, if the regulatory response to rising operating costs and higher capital costs is inadequate or untimely, or if the utility is not given the opportunity to recover the higher costs because of political factors or inadequate regulation, the business risk premium rises further, along with capital costs. Regulation can also diminish business risk. Bonded rate increases, adoption of forward test years, and automatic adjustment mechanisms such as fuel adjustment clauses are examples of attempts to lower regulatory risk. Decisions of various regulatory agencies such as the Board, the Environmental Protection Agency, and others impact utility finances directly. In short, regulation can increase business risk if it does not provide adequate returns and/or if it does not provide the utility with the opportunity to earn a fair rate of return.

Financial risk stems from the method used by the firm to finance its investments and is reflected in its capital structure. It refers to the additional variability imparted to income available to common shareholders by the employment of fixed cost financing: debt and preferred stock capital. Although the use of fixed cost capital can offer financial advantages through the possibility of leveraging of be supported by the company's earnings before any return can be made available to the common shareholder. The greater the percentage of fixed charges to the total income of the company, the greater the financial risk. The use of fixed cost financing introduces additional variability into the pattern of net earnings over and above that already conferred by business risk, and may even introduce the possibility of default and bankruptcy in unusual cases.

Variations in operating earnings cause amplified variations in equity returns when debt financing is used. The spread in equity returns is wider in the case of debt financing, and the greater the leverage, the greater the spread and the greater the cost of common equity.

Q. Please explain why the business risks faced by power generation have increased in recent years.

A. The business risks faced by power generation have intensified relative to the risks of the transmission & distribution ("T&D") business. The state of competition in an industry depends on four basic competitive forces:

- the threat of new entrants
- the degree of rivalry among existing firms
- the threat of substitute products
- the bargaining power of customers

All four forces have moved in the direction of more intense competition on the power generation side of the business. First, entry barriers have eroded. The traditional role of electric utilities has changed and continues to change drastically due to growing competition in the power generation industry and recent governmental and judicial actions. Competition has emerged in that business as regulatory barriers have been removed, for example unbundled facility elements and equal access to networks. Regulatory policy has encouraged a competitive bulk wholesale power market by requiring utilities to provide wheeling and connection services.

Second, the number of new entrants and/or the intensity of competition between existing market participants have increased. Sweeping regulatory reform have stimulated competitive forces and attracted new participants in the energy production markets. For example, non-utility generators (NUGs), self-generators, independent power producers (IPPs), and exempt wholesale generators (EWGs) have

[illegible]

investor-owned utilities, municipal utilities, NUGs, demand-side management providers, self-generation, fuel cells, and photovoltaics.

Lastly, the bargaining power of customers is increasing, particularly that of cost-conscious industrial-commercial users with viable least-cost alternatives. Large industrial customers are prime targets for new cream-skimming competitors, to the extent that rates are not reflective of costs.

In short, disintegrating entry barriers, intensifying rivalry among the rising number of competitors, more substitute products, and powerful buyers with many energy alternatives result in a highly competitive energy production market.

As a result of all these competitive and regulatory developments, the business risk and financial risk dynamics of the power generation business have been permanently altered. Investors have a difficult task in forecasting demand, market share, financing requirements, earnings, and cash flows in this fluid environment.

Q Does the investment community believe that the power generation business has higher investment risks than the T&D business?

A. Yes, it does. In a September 1998 article discussing bond rating methods for electric companies, Standard and Poor's confirms the view that fully-integrated electric operations are expected to exhibit higher risk profiles than transmission and distribution operations:

> *Owing to the relatively low business risk of large transmission systems and regulated distribution systems (the "wires" business), business profile assessments in this area should fall within the 1-4 [low risk] range. The generation business is the most risky, reflecting the competitive nature of this business, and generators generally receive business*

> *profile [risk] assessments in the mid- to lower-end of the range....*
>
> *Transmission and distribution operations are typically low risk relative to generation operations... .*
>
> *Competitive pressures in the transmission and distribution businesses are generally quite limited by virtue of franchise monopolies. While introducing competition into the generation business and creating national or international power exchange systems is increasingly popular worldwide, there is near unanimous agreement that transmission and distribution systems should largely remain monopolies....* (Standard & Poor's Infrastructure Finance, "Rating Methodology for Global Power Utilities, September 1998, pp. 61-68).

In October 1999, Standard and Poor's published an updated version of the report cited above and reiterated its position regarding generation investment risks.[1] Standard and Poor's remains firm in the view that fully-integrated electric operations are expected to exhibit higher risk profiles than transmission and distribution operations.

Another major bond rating agency, Moody's Investors Service, while cautioning its subscribers that electric distribution companies' credit profiles will vary depending on the circumstances of each company, also recognizes as a general matter that fully integrated electric utilities will have higher risk profiles than transmission and distribution operations.

While the US is only beginning to experience any legal disaggregation of its vertically-integrated utilities, a trend which has a very long way to go in the transformation, other countries have completed the legal disaggregation of their distribution, transmission and generation businesses. Our experience rating distributors in other countries and in other energy sectors indicates that those assumptions are substantially correct....

• *In general, distribution companies, regardless of their business profiles, exhibit lower business risks that*

• *"Pure" largely regulated distribution companies—that is, those with virtually no exposure to generation or other highly competitive and volatile energy-related businesses—can tolerate significantly lower interest or fixed charge coverage and higher leverage ratios than traditional US investor-owned utilities (IOUs) and still achieve the same rating.* (Moody's Investors Service, Global Credit Research, Special Comment, "Future Electric Distributors: More Stable than Generators, But Not Risk Free," October 1997).

A. Yes, they have. Both Moody's and Standard and Poor's ("S&P") report that fully integrated companies are expected to be capitalized with less leverage (less debt and more equity) than electric distribution operations in recognition of the lower business risks of the latter. For example, S&P reports in the aforementioned article regarding bond rating methodology for power companies worldwide that the median debt-to-capital ratio projected for "A" and "BBB"-rated electricity generators ranges from 35% to 45%. Whereas for transmission and distribution operations, S&P projects median debt-to-capital ratios of 55% and 65% for "A" and "BBB"-rated companies, respectively. The following table was taken in part from the article which details S & P's financial medians:

Table 1.

	Total debt to Total Capital (%)	
	A	BBB
Trans. and Distribution Cos.	55	65
Generators	35	45
Vertically Integrated Cos.	45	56

The data in the table demonstrates that "A"-rated T&D companies have a projected median debt-to-total capital ratio of about 55% (which implies a total equity ratio of 45%). This capitalization ratio is much more highly leveraged than the level S&P projects for "A"-rated generators (65% equity, 35% debt). A similar trend applies to "BBB-rated" companies.

Q. Dr. Morin, because MidAmerican's GDMEC will be subject to rate regulation by the Board, why is deregulation relevant to the determination of GDMEC's return on common equity?

A. The return on equity is based about capital attraction. To assess an investment, investors necessarily look to the future, because they can only obtain a return on their investment based upon what happens in the future. With a 25-year life, an investor must consider the prospects for cost recovery over that period of time. While deregulation of generation may not be imminent in Iowa today, it is hard to imagine that the status quo will continue over the next quarter century. Accordingly, the future risks as discussed by the rating agencies are pertinent to today's consideration of the determination of the cost of common equity.

Q. Dr. Morin, given the changing risks of the electric utility industry, what is your opinion regarding the cost of equity differential between the regulated (T&D) and unregulated (generation) functions?

A. Historically, each function of a vertically integrated electric utility possessed similar risk characteristics by virtue of the protection afforded by the regulatory umbrella, and, therefore, merited similar allowed returns on equity. For the reasons discussed above, investors now perceive higher investment risks in the generation function with the gradual disappearance of the regulatory umbrella.

It does not necessarily follow that the risks facing the T&D function have diminished, and, in fact they may well have escalated. While the business risks of the generation function have escalated markedly following the introduction of competition, the business risks of the distribution function have intensified as well, due to the intensifying competition in the energy services business and to regulatory uncertainties. The electricity distribution business is evolving into two distinct businesses, a facilities-based distribution business and a customer-focused energy service business.

The capital-intensive, facilities-based distribution segment will continue to offer common carrier service under fairly traditional monopolistic conditions, and would retain many of the characteristics that used to apply to all utilities: a monopoly on supply, a cost-plus mark-up based on orthodox rate of return/rate base regulation and growth depending on the economics of its service territory. The distribution utility will continue to retain the excess baggage and remnants of traditional regulation, including social policy, cross-subsidization, lifeline rates, and the obligation to purchase power for an unknown and varying group of its ratepayers as a provider of last resort. The latter will result in supply (power procurement) risks. The orphaned wires business will no longer enjoy the benefits of vertical integration.

Rates are very likely to continue being set under the auspices of rate of return/rate base regulation augmented by some form of performance-based ratemaking or incentive regulation, which carries its own set of unique risks. In the near term, the business risk profile of this segment is likely to remain at current levels relative to industrials, with upside profitability largely constrained by regulation. In the longer term, when the full forces of customer choice come to bear, the facilities-based segment will experience much of the same risk intensification that the generation segment is undergoing now. For example, competition from distributed generation and multi-fuel companies will augment risk.

The low capital-intensity energy service business is evolving into a far more competitive business, with regulation likely to recede substantially, offering more upside profitability potential and greater downside risk potential. Only those players with a sustainable competitive advantage will prevail. Achievement of the latter will depend on several factors, including the ability to develop unbundled products and creative pricing, good service reputations, and good knowledge of customer needs. It is not unreasonable to foresee widespread corporate mergers and recombinations in this segment of the distribution business, in the pursuit of economies of scale in promotion and advertising and the ability to establish a national presence.

Thus, at a minimum, the regulated T&D function remains at the very least as risky as in the past and most likely riskier. Thus, a vertically integrated electric utility that is divested of its generation function to become a T&D business will not necessarily be affected with lower risks.

Q. **Dr. Morin, how do you estimate the risk of an individual business segment such as the power generation business?**

A. Risk-averse investors require higher returns from higher risk investments. This implies that the expected return, or cost of capital, for a higher risk investment exceeds that of a lower risk investment. Viewing the various unbundled businesses of a vertically integrated electric utility (generation, T&D) on a stand-alone basis just like any other corporate investment, the higher the risk of that investment, the higher the expected return.

In theory, the latter can be calculated for each individual business segment as long as reliable and relevant market and historical information are available on each entity and/or on comparable risk investments, which are publicly traded. The traditional techniques of Discounted Cash Flow (DCF) and CAPM can then be applied to those comparable risk surrogates to measure the cost of capital.

Q. Please briefly describe the pure-play methodology.

A. The principal methodology to determine the cost of equity for a business segment is the Pure-Play technique. This approach consists of identifying publicly-traded companies which are most similar to the business segment in question, and then apply the traditional techniques of CAPM and DCF to the proxy firms. The average cost of equity for these companies can be used as an estimate of equity cost for the business segment. For example, a pure-play power generation business such as MidAmerican's electricity generation business would have a similar risk profile equal to that of wholesale power generators, as discussed later in my testimony. The betas of wholesale power generators can therefore be used as proxies for the unobservable beta of MidAmerican's power generation business and used in the CAPM to infer the cost of capital for that business.

CAPM ESTIMATES

Q. Please describe your application of the CAPM risk premium approach.

A. I developed several CAPM estimates based on the plain CAPM and on an empirical approximation to the CAPM ("ECAPM"). The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). For the risk-free rate, I used 5.5%. For the market risk premium, I used 7.4%. For beta, I used the average beta of the various comparable groups adjusted for capital structure differences. These inputs to the CAPM are explained below.

Q. **What security did you use as a proxy for the risk-free rate in your CAPM analyses?**

A. To implement the CAPM method, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the actual yields on long-term Treasury bonds. Long-term rates are the relevant benchmarks when determining the cost of common equity, rather than short-term interest rates. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are also used by foreign governments, companies, and individuals as a temporary safe-house for money. Short-term rates are largely administered rates.

As a practical matter, it is inappropriate to relate the return on common stock to the yield on short-term instruments. This is because short-term rates, such as the yield on 90-day Treasury bills, fluctuate widely leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury bill yields reflect the impact of factors different from those influencing long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

The level of U.S. Treasury long-term bond yields prevailing in September 2001 was 5.5%.

Q. What market risk premium estimate did you use in your CAPM analysis?

A. For the market risk premium, I used 7.4%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. Two studies guided the assumed range. First, the Ibbotson Associates study of historical returns from 1926 to 2000 shows that a broad market sample of common stocks out performed long-term Treasury bonds by 7.3%. Second, a DCF analysis applied to the aggregate equity market indicates a prospective market risk premium of 7.5%. The average of the two estimates is 7.4%.

Q. Why did you use long time periods in arriving at your historical market risk premium estimate?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have, therefore, ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the historical equity risk premium estimated follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. Since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. **Please describe your prospective approach in deriving the market risk premium in the CAPM analysis.**

A. For my second estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using Value Line's "Value Line Investment Survey for Windows" ("VLIS") software. The dividend yield on the aggregate market is currently 2.32% (VLIS 9/2001 edition), and the projected growth for the more than 5000 stocks covered by Value Line is in the range of 5.94% to 14.61%. Adding the two components together produces an expected return on the aggregate equity market in the range of 8.26% to 16.93%, with a midpoint of 12.6%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.83%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings this estimate to approximately 13.03%. The implied risk premium is therefore 7.53% over long-term U.S. Treasury bonds that are currently yielding 5.5%. The average of the historical estimate and the prospective estimate is 7.4%, which is my estimate of the current market risk premium.

Q. Please describe the beta measure of risk.

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta" or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement of the rates of return to a stock with those of the market as a whole. Therefore, it indicates the change in the rate of return on a stock associated with a one-percentage point change in the rate of return on the market. The beta coefficient thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation that are reflected in investors' return requirements.

Technically, the beta of a stock is a measure of the covariance of the return on the stock with the return on the market as a whole. Accordingly, it measures dispersion in a stock's return that cannot be reduced through diversification. In abstract theory for a large diversified portfolio, dispersion in the rate of return on the entire portfolio is the weighted sum of the beta coefficients of its constituent stocks.

Q. What betas did you select for your CAPM analyses?

A. MidAmerican's investment in the GDMEC is not a publicly traded entity, and therefore proxies must be utilized. It is reasonable to postulate that unregulated generation companies provide reasonable proxies for the risks and returns required for the Company's power generation investment. In addition to examining wholesale electric generating companies, I have also examined the risks and returns required for three other industries which produce commodities with capital-intensive production processes: oil and gas exploration, telecommunications, and diversified natural gas producers.

As a first proxy for the Company's power generation business, I examined the betas of wholesale power generation companies designated as "power companies" by Value Line. The group is shown in Exhibit RAM-2. The average beta for the group is 1.13, as shown in Column (1).

As a second proxy, I have examined the betas of widely-traded oil and gas producers contained in Value Line's "Petroleum Producing" universe with a market value in excess of $500 million. The group is shown in Exhibit RAM-3. The average beta for the group is 0.83. The third proxy includes widely-traded telecommunications companies contained in Value Line's "Telecommunications Service" universe with a market value in excess of $500 million. The group is shown in Exhibit RAM-4. The average beta for the group is 1.36. Finally, for the fourth proxy, I have examined the betas of widely-traded natural gas producers designated as "Natural Gas Diversified" universe by Value Line with a market value in excess of $500 million. The group is shown in Exhibit RAM-5. The average beta for the group is 0.77. The following table summarizes the four beta estimates.

Original Beta Estimates

Proxy Group	Beta
Wholesale Electric Generators	1.13
Oil & Gas Producers	0.83
Telecommunications Services	1.36
Diversified Natural Gas	0.77

Q. Are those beta estimates directly applicable to MidAmerican's investment in the GDMEC?

A. No, they are not. The difficulty with the pure-play approach is that although the reference companies may have the same business risk, they may have different capital structures. The observed beta for a company's stock reflects both business risk and financial risk. Business risk is the risk associated with a company's line of

business. Financial risk arises from the extent to which the company is financed by the issuance of debt. The more debt a company issues, the more financial risk that is borne by the holders of the company's equity. In order to correctly apply the CAPM to estimate the return on equity for the Company's power generation assets, the observed betas of the companies in the various proxy groups must first be unlevered (removing the effect of the company's debt ration) to calculate the beta matching each company's business risk and then relevered at MidAmerican's debt ratio.

Q. How do you adjust betas for capital structure differences?

A. As discussed above, when a group of companies are considered comparable in every way except for capital structure, their betas are not directly comparable. Fortunately, there is a technique for adjusting betas for capital structure differences. Given a company's stock beta ("levered beta") and its equity ratio, an unlevered beta, purged from any financial risk, can be computed. This unlevered beta, or pure business risk beta, measures the business risk component of the firm's total risk or, alternately, The fundamental idea is contained in the following relationship, which is derived in Appendix B:

Unlevered Beta = Levered Beta x Equity Ratio

$$\beta_U = \beta_L \times E/C$$

where β_U is the unlevered beta, β_L is the levered beta, E is the amount of equity capital, and C is the total capital invested. The ratio E/C is the equity ratio. For example, for a company with an equity ratio of 60% and a beta of 0.80, its unlevered beta is 0.80 x 0.60 = 0.48.

Column 3 of Exhibits RAM-2, RAM-3, RAM-4, and RAM-5 shows the calculation of unlevered beta for each of the four proxy groups, given their respective equity ratios and stock betas. The average unlevered beta is 0.77, 0.52, 0.71, and 0.36 for the power generators, oil and gas production, telecommunications, and diversified natural gas groups, respectively.

A beta for MidAmerican's investment in the GDMEC can be estimated, using the same relationship in reverse. Given an estimate of MidAmerican's power generation business risk beta and its common equity ratio, its stock beta can be inferred from the above equation. Column 5 of Exhibits RAM-2, RAM-3, RAM-4, and RAM-5 shows the calculation of MidAmerican's levered beta. This is obtained by dividing the unlevered beta of Column 3 by MidAmerican's estimated consolidated common equity ratio of 50% in Column 4. The resulting beta for MidAmerican's investment in the GDMEC is 1.54, 1.03, 1.43, and 0.71 using the power generators, oil and gas production, telecommunications, and diversified natural gas groups as proxies, respectively. The following table summarizes the four relevered beta estimates.

Relevered Beta Estimates

Proxy Group	Beta
Wholesale Electric Generators	1.54
Oil & Gas Producers	1.03
Telecommunications Services	1.43
Diversified Natural Gas	0.71

Q. What are your CAPM estimates of MidAmerican's power generation business?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.5%, a market risk premium of 7.4%, and the average betas of 1.54, 1.03, 1.43, and 0.71 from the four proxy groups, the CAPM estimates are 16.9%, 13.1%, 16.1%, and 10.8% for the power generators, the oil and gas production, the telecommunications, and diversified natural gas groups, respectively. The estimates become 17.2%, 13.4%, 16.4%, and 11.1% with flotation costs, discussed later in my testimony. The table below summarizes the CAPM estimates obtained from the four proxy groups.

CAPM Estimates

Proxy Group	ROE
Wholesale Electric Generators	17.2
Oil & Gas Producers	13.4
Telecommunications Services	16.4
Diversified Natural Gas	11.1
AVERAGE	**14.5**

The average CAPM estimate from the four proxy groups is 14.5%, which exceeds 13.25%, the level the Company is proposing.

Q. What are your ECAPM estimates of MidAmerican's electricity generation operations?

A. It is well established in the academic finance literature that the CAPM produces a downward-biased estimate of equity cost for companies with a beta of less than 1.00. Expanded CAPMs have been developed which relax some of the more restrictive assumptions underlying the traditional CAPM responsible for this bias, and thereby enrich its conceptual validity. These expanded CAPMs typically produce a risk-return relationship that is "flatter" than the traditional CAPM's prediction, consistent with the empirical findings of the finance literature. The following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

Inserting 5.5% for R_F, a market risk premium of 7.4% for R_M - R_F and the average beta estimates from the four proxy groups in the above equation, the ECAPM estimates are 15.9%, 13.1%, 15.3%, and 11.3% from the power generators, oil and gas production, telecommunications, and diversified natural gas groups, respectively. The estimates become 16.2%, 13.4%, 15.6%, and 11.6% with flotation costs, discussed later in my testimony. The table below summarizes the ECAPM estimates obtained from the four proxy groups.

ECAPM Estimates

Proxy Group	**ROE**
Wholesale Electric Generators	16.2
Oil & Gas Producers	13.4
Telecommunications Services	15.6
Diversified Natural Gas	11.6
AVERAGE	**14.2**

The average ECAPM estimate from the four proxy groups is 14.2%, which again exceeds 13.25%, the level the Company is proposing.

DCF ESTIMATES

Q. Please describe the DCF approach to estimating the cost of equity capital.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend during the coming year

P_o = current stock price

g = expected growth rate of future dividends

The traditional DCF formula, known as the "single-stage" DCF model, states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_0, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and from an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known. The assumptions are discussed in detail in Chapter 4 of my book, <u>Regulatory Finance</u>. The traditional DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The traditional DCF model also assumes that dividends are paid annually when in fact dividend payments are normally made on a quarterly basis.

Q. Is the constant growth DCF model applicable under all circumstances?

A. No, it is not. For companies in a mature industry, such as the electric utility industry had been, a constant growth rate is a reasonable assumption. For companies in a more dynamic industry, such as the wholesale electric generation business, this assumption may not be reasonable and the dividend growth rate may be expected to decline toward a lower long-run level.

Q. How did you estimate the cost of equity with the constant growth DCF model?

A. I applied the DCF model to the same four proxy groups used in the CAPM analyses for MidAmerican's power generation business. To apply the DCF model, two components are required: the expected dividend yield (D_1/P_0) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model is obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ is the current price of the security at the time of estimating the cost of equity. The reason is that current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices. In implementing the DCF model, I have used the spot dividend yields reported in the September 2001 edition of VLIS.

Q. **How did you estimate the growth component of the DCF model?**

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed. As a proxy for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Specifically, I used analysts' long-term growth forecasts contained in Zacks Investment Research web site as

Q. How does the DCF model apply to companies who do not pay dividends?

A. Many companies in the comparable group of wholesale electric generating companies and in the other industry groups do not currently pay a dividend. However, this does not mean that the single-stage calculation breaks down. If one considers the standard DCF equation:

$$K_e = D_1/P_o + g$$

Then, the dividend yield term becomes zero, and the return on equity is equal to the growth rate g.

Q. What DCF results did you obtain for the power generation group?

A. Exhibit RAM-6 page 1 displays the twelve power companies that make up Value Line's power group and for which a long-term growth forecast is available from Zacks. None of these companies pay a dividend, so that the return on equity is equal to the growth rate. As shown on Column 1 of Exhibit RAM-6 page 1, the average long-term growth forecast obtained from Zacks is 27.4% for this group, which also equals the return on equity.

Using Value Line's long-term earnings growth forecast of 30.1% instead of the Zacks consensus forecast, the return on equity is also 30.1%. Such forecasts were available for only five of the power generation companies. This analysis is displayed on page 2 of Exhibit RAM-6.

Q. What DCF results did you obtain for the oil and gas producers group?

A. Exhibit RAM-7 displays the five companies that make up Value Line's oil and gas producers group. Only dividend-paying companies were retained. As shown on Column 2 of page 1 of Exhibit RAM-7, the average long-term growth forecast obtained from Zacks is 16.5% for this group. Adding this growth rate to the average expected dividend yield of 0.8% in Column 3 produces an estimate of equity costs of 17.2% for the group, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 17.3%, shown in Column 5.

Using Value Line's long-term growth forecast instead of the Zacks consensus growth forecast, the return on equity for the group is 23.6%. This analysis is displayed on page 2 of Exhibit RAM-7.

Q. What DCF results did you obtain for the telecommunications group?

A. Exhibit RAM-8 displays the nine companies that make up Value Line's telecommunications services group and that pay a dividend. As shown on Column 2 of page 1 of Exhibit RAM-8, the average long-term growth forecast obtained from Zacks is 13.0% for this group. Adding this growth rate to the average expected dividend yield of 1.8% in Column 3 produces an estimate of equity costs of 14.8% for the group, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 4 brings the return on equity estimate to 14.9%, shown in Column 5. The truncated average, obtained by removing the high and low estimates from the computation of the mean, is 14.0%.

Using Value Line's long-term growth forecast instead of the Zacks consensus growth forecast, the return on equity for the group is 14.2%. This analysis is displayed on page 2 of Exhibit RAM-8.

Q. What DCF results did you obtain for the diversified natural gas group?

A. Exhibit RAM-9 displays the seventeen companies that make up Value Line's diversified natural gas group and that pay a dividend. As shown on Column 2 of page 1 of Exhibit RAM-9, the average long-term growth forecast obtained from Zacks is 14.4% for this group. Adding this growth rate to the average expected dividend yield of 2.2% in Column 3 produces an estimate of equity costs of 16.6% for the group, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 4 brings the return on equity estimate to 16.7%, shown in Column 5. The truncated average is 16.8%.

Using Value Line's long-term growth forecast instead of the Zacks consensus growth forecast, the return on equity for the group is 23.4%. This analysis is displayed on page 2 of Exhibit RAM-9.

Q. Please summarize your constant growth DCF estimates.

A. Ignoring the estimates produced by the aggressive Value Line growth forecasts, the table below summarizes the constant growth DCF estimates for MidAmerican's investment in the GDMEC obtained using the consensus analysts' growth forecasts from Zacks:

CONSTANT GROWTH DCF ESTIMATES

	ROE
Wholesale Electric Generators	27.4
Oil & Gas Producers	17.3
Telecommunications Services	14.0
Diversified Natural Gas	16.8
AVERAGE	**18.9**

The average constant growth DCF estimate from the four proxy groups is 18.9%. To the extent that some of the constant growth rates that underlie these DCF estimates are very high and, therefore, not sustainable over an infinite period of time, I view these estimates are somewhat unrealistic. To the extent that the two-stage DCF estimates that follow recognize this fact, more weight should be placed on the latter estimates than the former.

Q. Please describe your two-stage DCF methodology.

A. As noted above, for companies in a relatively undeveloped industry like the wholesale generation business, or for companies experiencing very high growth rates, the assumption of a constant growth rate may not be reasonable and the growth rate may be expected to decline toward a lower long-run level over time. One way to modify the single-stage DCF model is to specify the growth rate as a weighted average of short-term and long-term growth rates.

The blended growth rate is calculated as a weighted average giving two-thirds weight to the Zacks five-year growth projections and one-third to long-range projections of growth in Gross Domestic Product (GDP) projected for the period 2002-2025 by Standard & Poor's DRI. FERC has adopted such a method for determining the return on equity for gas utilities.

forecast of 6.2% for the U.S. economy. Column 3 computes the weighed average growth, giving 2/3 weight to Column 1 and 1/3 weight to Column 2. The resulting average growth rate of 20.3% for the group in Column 4 is the return on equity, given that these companies do not pay dividends.

For the oil and gas group, the analysis is displayed on Exhibit RAM-11. Column 2 shows the analyst consensus growth forecast for the next five years from Zacks, and Column 3 shows the long-range GDP forecast of 6.2% for the U.S. economy. Column 4 computes the weighed average growth, giving 2/3 weight to Column 2 and 1/3 weight to Column 3. Adding the blended growth rate of 13.0% to the average expected dividend yield of 0.8% in Column 5 produces an estimate of equity costs of 13.8% for the group, unadjusted for flotation costs. Allowance for flotation costs to the results of Column 6 brings the return on equity estimate to 13.83%, shown in Column 7.

The analyses for the two remaining groups proceed in an identical manner to that of the oil and gas group, and are shown on Exhibits RAM-12 and RAM-13.

Q. **Please summarize your two-stage DCF estimates.**

A. The table below summarizes the two-stage DCF estimates for the industry groups. All of the estimates are comparable to or greater than 13.25%, and three of the four are substantially greater.

TWO-STAGE DCF ESTIMATES

	ROE
Wholesale Electric Generators	20.3
Oil & Gas Producers	13.8
Telecommunications Services	12.1
Diversified Natural Gas	14.1
AVERAGE	**15.1**

The average two-stage DCF estimate from the four proxy groups is 15.1%. As discussed earlier, I place more weight on the two-stage DCF estimates than the single-stage constant growth estimates.

Q. **Dr. Morin, you made an explicit adjustment in your CAPM and ECAPM estimates of the generation cost of equity to adjust for capital structure differences. Is such an adjustment possible in your DCF calculations?**

A. Currently, there are no formal theories linking DCF estimates with capital structure differences, unlike the case earlier with the CAPM where such theories are available. Suffice it to say that to the extent that the DCF estimates are drawn from a less levered (lower debt ratio) group of companies, the expected equity return applicable to the more highly levered GDMEC is downward-biased. In the interest of conservatism and owing to the lack of formal theory to quantify the risks associated with higher leverage in the DCF model, I have not made any formal upward adjustment to the DCF estimates, and I consider them as floor estimates.

Q. **Please describe the need for a flotation cost allowance.**

A. All the market-based estimates (CAPM and DCF) reported above include an adjustment for flotation cost. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are incurred, they are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is routinely done for bond and preferred stock issues by most regulatory commissions. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is regularly discussed and applied in most corporate finance textbooks.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs were not expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix A to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Appendix A, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. That is, dividing the average expected dividend yield of around 5.6% for utility stocks by 0.95 yields 5.9%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continues for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the company.

SUMMARY

Q. Please summarize your results.

A. The table below recapitulates the average result obtained from the various methodologies applied to each of the four groups of comparables. I have omitted the results from the constant growth single-stage DCF approach for reasons discussed earlier.

SUMMARY OF RESULTS

	ROE
Two-stage DCF	15.1
CAPM	14.5
Empirical CAPM	14.2
AVERAGE	**14.6**

The average ROE is 14.6%, and the results lie within a range of about 14.0% to 15.0%. These estimates show that the Company's proposed return of 13.25% on its investment in the GDMEC for the life of the unit as a regulated utility investment is below the returns required in comparable industries. As a result, this return should be found reasonable by the Board.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management. Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1 % for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. Adding the two effects, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_0 + g$$

If P_0 is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_0 equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_0 + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_O are related to market price P_0 as follows:

$$P - fP = B_0$$
$$P(1 - f) = B_0$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving my DCF estimates of fair return on equity, it was therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 6-8 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 6-8 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 6. The stock is selling in the market for $25, investors expect the firm to pay a dividend of $2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1\text{-}f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are $23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 7, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 8. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH=	5.00%

EQUITY RETURN = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P (1-f) + g)	**14.47%**

COMPANY EARNS FLOTATION-ADJUSTED COST OF EQUITY
APPLIED ON ALL COMMON EQUITY
BEGINNING OF YEAR

YEAR	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)	CHANGE EARNINGS RETAINED (9)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65 45%	$1.188
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%	$1.247
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%	$1.309
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%	$1.375
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%	$1.443
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%	$1.516
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%	$1.591
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%	$1.671
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%	$1.754
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%	$1.842
			5.00%	5.00%		5.00%	5.00%		5.00%

COMPANY DOES NOT EARN THE FLOTATION-ADJUSTED COST OF EQUITY

YEAR	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	4.53%		4.53%	4.53%	

APPENDIX B

CALCULATING UNLEVERED BETAS

The beta of a company's assets equals the beta of its financing sources. The latter is the weighted beta of the company's debt capital and equity capital, with market values acting as weights:

$$\beta_{asset} = \beta_{debt}\,(\text{debt/debt+equity}) + \beta_{equity}(\text{equity/debt+equity}) \qquad (1)$$

Assume that corporate bonds have zero systematic risk, that is $\beta_{debt} = 0$ in the above equation. Equation (1) reduces to:

$$\beta_{asset} = \beta_{equity}(\text{equity/debt+equity}) \qquad (2)$$

The bracketed term is the equity ratio. Equation (2) then becomes:

$$B_{unlevered} = \beta_{levered} \times \text{equity ratio} \qquad (3)$$

RESUME OF ROGER A. MORIN

(Fall 2001)

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DATE OF BIRTH: 3/5/1945

PRESENT EMPLOYER: Georgia State University

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3

- Assistant Professor, University of Montreal School of Business, 1973-1976.

- Associate Professor, University of Montreal School of Business, 1976-1979.

- Professor of Finance, Georgia State University, 1979-2001

- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2001

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.

- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.

- Co-founder and Director Canadian Finance Research Foundation, 1977.

- Vice-President of Research, Garmaise Thomson & Associates [illegible]

Investment Management Consultants, 1980-1981.

- Executive Visions Inc., Board of Directors, Member

[illegible]

CORPORATE CONSULTING CLIENTS

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

American Water Works Company

Ameritech

Baltimore Gas & Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central South West Corp.

Cincinnatti Gas & Electric

Cinergy Corp

CORPORATE CONSULTING CLIENTS (CONT'D)

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Constellation Energy

Deerpath Group

Edison International

Edmonton Power Company

Engraph Corporation

Entergy Corp.

Entergy Gulf States Utilities, Inc.

Entergy Louisiana, Inc.

Florida Water Association

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California

GTE Northwest Inc

GTE Service Corp.

GTE Southwest Incorporated

Gulf Power Company

Havasu Water Inc.

Hope Gas Inc.

CORPORATE CONSULTING CLIENTS (CONT'D)

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Mountain Bell

Newfoundland Light & Power - Fortis Inc.

NewTel Enterprises Ltd.

New York Telephone Co.

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Board of Utilities

NUI Corp

NYNEX

Oklahoma G & E

CORPORATE CONSULTING CLIENTS (CONT'D)

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Price Waterhouse

PSI Energy

Public Service Elec & Gas

Quebec Telephone

Rochester Telephone

SaskPower

Sierra Pacific Resources

Southern Bell

Southern States Utilities

South Central Bell

Sun City Water Company

The Southern Company

Touche Ross and Company

Trans-Quebec & Maritimes Pipeline

US WEST Communications

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty, 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78

- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- The Management Exchange Inc., faculty member, 1981-2000.

NATIONAL SEMINARS:

Risk and Return on Capital Projects
Cost of Capital for Regulated Utilities
Capital Allocation for Utilities
Alternative Regulatory Frameworks
Utility Directors' Workshop
Shareholder Value Creation for Utilities
Real Options in Utility Capital Investments
Fundamentals of Utility Finance

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Phase-in Plans

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Publicly-owned Municipals

Telecommunications, CATV, Energy, Pipeline, Water

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES:

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Public Service Commission

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television and Telecomm. Commission

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

New York Public Service Commission

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Service Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Service Commission

Michigan Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC,Docket#R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, 1989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999

Southern States Utilities, 1995

CILCO 1995, 1999

Commonwealth Telephone 1996

Edison International 1996-8

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998

Detroit Edison, 1999

Entergy Gulf States, Texas, 2000

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences,1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2001
- Financial Management Association, 1978-2001

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982
- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982
- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983
- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.
- Committee on New Product Development, FMA, 1985
- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986
- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986
- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED:

"An Empirical Study of Multiperiod Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation "Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977
- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975
- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management

  Financial Review

  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital, " Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, (New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994

Driving Shareholder Value, McGraw-Hill, January 2001

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980, (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

An Economic & Financial Profile of the Canadian Cablevision Industry. Canadian Radio-Television & Telecomm. Commission (CRTC), 1978

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities [illegible]

Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company,1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981

"Firm Size and Beta Stability", Georgia State University College of Business, 1982

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2000
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000
- University Senate Committee on Commencement
- University Senate Committee on Information Technology
- University Senate Committee on Student Discipline

MIDAMERICAN GENERATION
BETA ESTIMATES
COMPARABLE RISK POWER COMPANIES

	Company	Industry	Beta (1)	% Common Equity (2)	Unlevered Beta (3)	MidAmerican % Common Equity (4)	MidAmerican Levered Beta (5)
1	AES Corp.	POWER	1.15	0.22	0.25	0.50	0.51
2	Amer. Superconductor	POWER	1.40	1.00	1.40	0.50	2.80
3	AstroPower Inc.	POWER	1.30	1.00	1.30	0.50	2.60
4	Ballard Power Sys.	POWER	1.20	1.00	1.20	0.50	2.40
5	Calpine Corp.	POWER	0.90	0.29	0.26	0.50	0.52
6	Covanta Energy	POWER	0.90	0.12	0.11	0.50	0.22
7	Energy Conversion	POWER	1.05	0.83	0.87	0.50	1.74
	AVERAGE		**1.13**	**0.64**	**0.77**	**0.50**	**1.54**

Source:
Column (1), (2): Value Line Investment Survey 9/2001
Column (3) = Column (1) times Column (3)
Column (4): Company estimate
Column (5) = Column (3) divided by Column (4)

MIDAMERICAN GENERATION
BETA ESTIMATES
COMPARABLE OIL & GAS PRODUCERS

	Company	Industry	Beta (1)	% Common Equity (2)	Unlevered Beta (3)	MidAmerican % Common Equity (4)	MidAmerican Levered Beta (5)
1	Anadarko Petroleum	OILPROD	0.80	0.63	0.50	0.50	1.01
2	Apache Corp.	OILPROD	0.75	0.58	0.44	0.50	0.87
3	Brown (Tom) Inc.	OILPROD	0.70	0.90	0.63	0.50	1.26
4	Burlington Resources	OILPROD	0.75	0.62	0.47	0.50	0.93
5	Chesapeake Energy	OILPROD	0.95	0.22	0.21	0.50	0.42
6	Enbridge Inc.	OILPROD	0.55	0.28	0.15	0.50	0.31
7	Evergreen Resources	OILPROD	0.75	0.64	0.48	0.50	0.96
8	Forest Oil	OILPROD	0.85	0.58	0.49	0.50	0.99
9	Houston Expl Co	OILPROD	0.90	0.62	0.56	0.50	1.12
10	Methanex Corp.	OILPROD	0.60	0.72	0.43	0.50	0.86
11	Noble Affiliates	OILPROD	0.75	0.62	0.47	0.50	0.93
12	Paramount Resources	OILPROD	0.75	0.57	0.43	0.50	0.86
13	Patterson-UTI Energy	OILPROD	1.30	0.94	1.22	0.50	2.44
14	Penn West Petroleum	OILPROD	0.80	0.59	0.47	0.50	0.94
15	Pioneer Natural Res.	OILPROD	1.00	0.36	0.36	0.50	0.72
	Pogo Producing	OILPROD	0.95	0.50	0.48	0.50	0.95
17	Precision Drilling	OILPROD	0.85	0.80	0.68	0.50	1.36
18	Rio Alto Exploration	OILPROD	0.85	0.52	0.44	0.50	0.88
19	St. Mary Land & Expl	OILPROD	0.85	0.92	0.78	0.50	1.56
20	Stone Energy	OILPROD	0.80	0.76	0.61	0.50	1.22
21	Suncor Energy	OILPROD	0.75	0.53	0.40	0.50	0.80
22	Swift Energy	OILPROD	0.90	0.71	0.64	0.50	1.28
	AVERAGE		**0.83**	**0.62**	**0.52**		**1.03**

Source:
Column (1), (2): Value Line Investment Survey 9/2001
Column (3) = Column (1) times Column (3)
Column (4): Company estimate
Column (5) = Column (3) divided by Column (4)

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MIDAMERICAN GENERATION
BETA ESTIMATES
COMPARABLE TELECOMMUNICATIONS COMPANIES

Company	Industry	Beta (1)	% Common Equity (2)	Unlevered Beta (3)	MidAmerican % Common Equity (4)	MidAmerican Levered Beta (5)
1 ALLTEL Corp.	TELESERV	0.80	0.52	0.42	0.50	0.83
4 Allegiance Telecom	TELESERV	2.10	0.63	1.32	0.50	2.65
5 Amer. Tower 'A'	TELESERV	1.80	0.54	0.97	0.50	1.94
7 BellSouth Corp.	TELESERV	0.85	0.58	0.49	0.50	0.99
9 CenturyTel Inc.	TELESERV	1.00	0.40	0.40	0.50	0.80
10 Citizens Communic.	TELESERV	0.85	0.34	0.29	0.50	0.58
11 Commonwealth Telephon	TELESERV	0.80	0.30	0.24	0.50	0.48
12 Crown Castle Int'l	TELESERV	1.85	0.41	0.76	0.50	1.52
14 Dycom Inds.	TELESERV	1.15	0.98	1.13	0.50	2.25
16 Gen'l Communication 'A'	TELESERV	1.00	0.31	0.31	0.50	0.62
17 Global Crossing Ltd.	TELESERV	1.85	0.55	1.02	0.50	2.04
18 IDT Corp.	TELESERV	1.25	0.89	1.11	0.50	2.23
21 Level 3 Communic.	TELESERV	1.95	0.38	0.74	0.50	1.48
22 McLeodUSA Inc.	TELESERV	1.85	0.42	0.78	0.50	1.55
23 Metromedia Fiber 'A'	TELESERV	2.20	0.46	1.01	0.50	2.02
24 NTL Inc.	TELESERV	1.40	0.33	0.46	0.50	0.92
25 Nextel Communic. 'A'	TELESERV	2.00	0.10	0.20	0.50	0.40
26 PanAmSat Corp.	TELESERV	1.25	0.79	0.99	0.50	1.98
27 Qwest Communic.	TELESERV	1.55	0.73	1.13	0.50	2.26
28 SBC Communications	TELESERV	0.85	0.65	0.55	0.50	1.11
29 Sprint Corp.	TELESERV	0.85	0.78	0.66	0.50	1.33
30 Sprint PCS Group	TELESERV	1.35	0.10	0.14	0.50	0.27
33 Telephone & Data	TELESERV	0.85	0.77	0.65	0.50	1.31
34 Time Warner Telecom Inc	TELESERV	2.50	0.45	1.13	0.50	2.25
35 U.S. Cellular	TELESERV	0.85	0.83	0.71	0.50	1.41
37 West Corp	TELESERV	0.90	0.95	0.86	0.50	1.71
40 WorldCom Inc.	TELESERV	1.05	0.75	0.79	0.50	1.58
AVERAGE		**1.36**	**0.55**	**0.71**	**0.50**	**1.43**

Source:
Column (1), (2): Value Line Investment Survey 9/2001
Column (3) = Column (1) times Column (3)
Column (4): Company estimate
Column (5) = Column (3) divided by Column (4)

Exhibit RAM-5 Page 1 of 1

MIDAMERICAN GENERATION
BETA ESTIMATES
DIVERSIFIED NATURAL GAS PRODUCERS

Company	Industry	Beta (1)	% Common Equity (2)	Unlevered Beta (3)	MidAmerican % Common Equity (4)	MidAmerican Levered Beta (5)
1 ATCO Ltd.	GASDIVRS	0.45	0.23	0.10	0.50	0.21
2 Cabot Oil & Gas 'A'	GASDIVRS	0.90	0.49	0.44	0.50	0.88
3 Devon Energy	GASDIVRS	0.75	0.59	0.44	0.50	0.89
4 EOG Resources	GASDIVRS	0.80	0.55	0.44	0.50	0.88
5 El Paso Corp.	GASDIVRS	0.80	0.35	0.28	0.50	0.56
6 El Paso Energy Partners	GASDIVRS	0.55	0.16	0.09	0.50	0.18
7 Enron Corp.	GASDIVRS	0.95	0.52	0.49	0.50	0.99
8 Equitable Resources	GASDIVRS	0.60	0.63	0.38	0.50	0.76
9 Kinder Morgan	GASDIVRS	0.60	0.40	0.24	0.50	0.48
10 Kinder Morgan Energy	GASDIVRS	0.75	0.62	0.47	0.50	0.93
11 Louis Dreyfus NatGas	GASDIVRS	1.00	0.47	0.47	0.50	0.94
12 Mitchell Energy 'A'	GASDIVRS	0.85	0.67	0.57	0.50	1.14
13 National Fuel Gas	GASDIVRS	0.55	0.51	0.28	0.50	0.56
14 Northern Border Partners	GASDIVRS	0.50	0.34	0.17	0.50	0.34
15 Ocean Energy	GASDIVRS	1.20	0.50	0.60	0.50	1.20
16 Plains Resources	GASDIVRS	0.90	0.04	0.04	0.50	0.07
17 Questar Corp.	GASDIVRS	0.65	0.58	0.38	0.50	0.75
18 San Juan Basin Rlty.	GASDIVRS	0.55	1.00	0.55	0.50	1.10
19 TEPPCO Partners L.P.	GASDIVRS	0.60	0.27	0.16	0.50	0.32
20 Vintage Petroleum	GASDIVRS	1.25	0.57	0.71	0.50	1.43
21 Western Gas Res.	GASDIVRS	0.70	0.29	0.20	0.50	0.41
22 Williams Cos.	GASDIVRS	0.95	0.36	0.34	0.50	0.68
23 XTO Energy Inc	GASDIVRS	0.90	0.37	0.33	0.50	0.67
AVERAGE		**0.77**	**0.46**	**0.36**	**0.50**	**0.71**

Source:
Column (1), (2): Value Line Investment Survey 9/2001
Column (3) = Column (1) times Column (3)
Column (4): Company estimate
Column (5) = Column (3) divided by Column (4)

POWER GENERATION COMPANIES
DCF ANALYSIS
ANALYSTS' GROWTH FORECASTS

	Company	Analysts' Growth Forecast (1)
1	AES Corp.	26.0
2	Active Power	35.0
3	Amer. Superconductor	23.5
4	AstroPower Inc.	40.0
5	Ballard Power Sys.	26.7
6	Calpine Corp.	33.8
7	Caminus Corp.	32.5
8	Capstone Turbine	26.7
9	Covanta Energy	16.0
10	Mirant Corp.	22.5
11	NRG Energy	22.0
12	Orion Power Hldgs.	23.8
	AVERAGE	**27.4**

Source:
Column (1): Zacks Investment Research Web site.

POWER GENERATION COMPANIES
DCF ANALYSIS
VALUE LINE GROWTH FORECASTS

	Company	Value Line Projected EPS Growth (1)
1	AES Corp.	24.5
2	AstroPower Inc.	32.0
3	Calpine Corp.	33.5
4	Mirant Corp.	31.5
5	NRG Energy	29.0
	AVERAGE	**30.1**

Source:
Column (1): VLIS 9/2001

OIL & GAS PRODUCING COMPANIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Anadarko Petroleum	0.4	19.7	0.5	20.2	20.2
2 Apache Corp.	0.6	17.1	0.7	17.8	17.8
3 Burlington Resources	1.4	13.8	1.6	15.4	15.5
4 Noble Affiliates	0.5	16.3	0.5	16.8	16.9
5 Pogo Producing	0.5	15.4	0.5	15.9	16.0
AVERAGE	**0.7**	**16.5**	**0.8**	**17.2**	**17.3**

Notes:
Column 1: Value Line Investment Survey for Windows, 9/2001
Column 2 = Zacks Investment Research Web site, 9/2001
[illegible]

Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

OIL & GAS PRODUCING COMPANIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Anadarko Petroleum	0.4	9.0	0.4	9.4	9.5
2 Apache Corp.	0.6	10.0	0.6	10.6	10.7
3 Burlington Resources	1.4	24.0	1.8	25.8	25.9
4 Noble Affiliates	0.5	27.0	0.6	27.6	27.6
5 Pogo Producing	0.5	43.5	0.7	44.2	44.2
AVERAGE	**0.7**	**22.7**	**0.8**	**23.5**	**23.6**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 9/2001
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

TELECOMMUNICATIONS SERVICE COMPANIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 ALLTEL Corp.	2.3	12.2	2.6	14.8	15.0
2 AT&T Corp.	0.8	9.0	0.9	9.9	9.9
3 BellSouth Corp.	2.0	10.1	2.2	12.3	12.5
4 CenturyTel Inc.	0.6	11.1	0.6	11.7	11.8
5 Qwest Communic.	0.3	26.1	0.3	26.4	26.4
6 SBC Communications	2.5	10.6	2.7	13.3	13.5
7 Sprint Corp.	2.2	6.9	2.4	9.3	9.4
8 Telephone & Data	0.6	21.7	0.7	22.4	22.4
9 Verizon Communic.	3.1	9.5	3.4	12.9	13.1
AVERAGE	**1.6**	**13.0**	**1.8**	**14.8**	**14.9**
TRUNCATED AVERAGE					**14.0**

Notes:
Column 1: Value Line Investment Survey for Windows, 9/2001
Column 2 = Zacks Investment Research Web site, 9/2001
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

TELECOMMUNICATIONS SERVICE COMPANIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 ALLTEL Corp.	2.3	15.0	2.7	17.7	17.8
2 AT&T Corp.					
3 BellSouth Corp.	2.0	13.5	2.3	15.8	15.9
4 CenturyTel Inc.	0.6	10.0	0.6	10.6	10.6
5 Qwest Communic.					
6 SBC Communications	2.5	10.5	2.7	13.2	13.3
7 Sprint Corp.	2.2	2.5	2.3	4.8	4.9
8 Telephone & Data	0.6	30.5	0.7	31.2	31.3
9 Verizon Communic.	3.1	9.5	3.4	12.9	13.1
AVERAGE	**1.9**	**13.1**	**2.1**	**15.2**	**15.3**
TRUNCATED AVERAGE					**14.2**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 9/2001
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

NATURAL GAS DIVERSIFIED COMPANIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Cabot Oil & Gas 'A'	0.7	10.0	0.8	10.8	10.8
2	Devon Energy	0.5	14.2	0.5	14.7	14.8
3	Dynegy Inc. 'A'	0.7	22.2	0.9	23.1	23.1
4	EOG Resources	0.5	13.1	0.6	13.7	13.7
5	El Paso Corp.	1.7	14.9	2.0	16.9	17.0
6	Enron Corp.	1.5	17.4	1.8	19.2	19.3
7	Equitable Resources	2.0	12.6	2.3	14.9	15.0
8	Kinder Morgan	0.4	21.6	0.4	22.0	22.0
9	Kinder Morgan Energy	5.9	11.9	6.6	18.5	18.9
10	Mitchell Energy 'A'	1.0	13.5	1.1	14.6	14.6
11	National Fuel Gas	4.2	11.4	4.7	16.1	16.3
12	Ocean Energy	0.8	25.4	1.0	26.4	26.5
13	Questar Corp.	3.2	11.4	3.6	15.0	15.2
14	TEPPCO Partners L.P.	6.6	8.6	7.1	15.7	16.1
15	Vintage Petroleum	0.9	16.7	1.1	17.8	17.8
16	Western Gas Res.	0.7	5.0	0.7	5.7	5.7
17	Williams Cos.	2.2	15.1	2.5	17.6	17.8
	AVERAGE	**2.0**	**14.4**	**2.2**	**16.6**	**16.7**
	TRUNCATED AVERAGE					**16.8**

Notes:
Column 1: Value Line Investment Survey for Windows, 9/2001
Column 2 = Zacks Investment Research Web site, 9/2001
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

NATURAL GAS DIVERSIFIED COMPANIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Cabot Oil & Gas 'A'	0.7	29.0	0.9	29.9	30.0
2	Devon Energy	0.5	19.5	0.5	20.0	20.1
3	Dynegy Inc. 'A'	0.7	28.0	0.9	28.9	29.0
4	EOG Resources	0.5	18.0	0.6	18.6	18.6
5	El Paso Corp.	1.7	14.5	1.9	16.4	16.5
6	Enron Corp.	1.5	26.5	1.9	28.4	28.6
7	Equitable Resources	2.0	22.5	2.5	25.0	25.1
8	Kinder Morgan	0.4	22.0	0.4	22.4	22.4
9	Kinder Morgan Energy	5.9	11.0	6.6	17.6	17.9
10	Mitchell Energy 'A'	1.0	9.5	1.0	10.5	10.6
11	National Fuel Gas	4.2	11.5	4.7	16.2	16.4
12	Ocean Energy	0.8	41.5	1.2	42.7	42.7
13	Questar Corp.	3.2	12.0	3.6	15.6	15.8
14	TEPPCO Partners L.P.	6.6	5.0	6.9	11.9	12.3
15	Vintage Petroleum	0.9	28.5	1.2	29.7	29.7
16	Western Gas Res.	0.7	66.0	1.1	67.1	67.1
17	Williams Cos.	2.2	23.5	2.7	26.2	26.4
	AVERAGE	2.0	22.9	2.3	25.1	25.2
	TRUNCATED AVERAGE					23.4

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 9/2001
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

POWER GENERATION COMPANIES
2-STAGE DCF ANALYSIS: ANALYSTS' FORECASTS

Company	Analysts' Growth Forecast (1)	Long-Term GDP Growth Forecast (2)	Weigthed Growth (3)	ROE (4)
1 AES Corp.	26.0	6.2	19.4	19.4
2 Active Power	35.0	6.2	25.4	25.4
3 Amer. Superconductor	23.5	6.2	17.7	17.7
4 AstroPower Inc.	40.0	6.2	28.7	28.7
5 Ballard Power Sys.	26.7	6.2	19.9	19.9
6 Calpine Corp.	33.8	6.2	24.6	24.6
7 Caminus Corp.	32.5	6.2	23.7	23.7
8 Capstone Turbine	26.7	6.2	19.9	19.9
9 Covanta Energy	16.0	6.2	12.7	12.7
10 Mirant Corp.	22.5	6.2	17.1	17.1
11 NRG Energy	22.0	6.2	16.7	16.7
12 Orion Power Hldgs.	23.8	6.2	17.9	17.9
AVERAGE	27.4	6.2	20.3	**20.3**

Notes:
Column 1 = Zacks Investment Research Web site, 9/2001
Column 2: Standard & Poor's DRI "The U.S. Economy: The 25-Year Focus"
Column 3 = Column 1 times 2/3 plus Column 2 times 1/3
Column 4 = Column 3

OIL & GAS PRODUCING COMPANIES
2-STAGE DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	Proj GDP Growth (3)	Weighted Growth (4)	% Expected Divid Yield (5)	Cost of Equity (6)	ROE (7)
1 Anadarko Petroleum	0.4	19.7	6.2	15.2	0.5	15.7	15.7
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3 Burlington Resource:	1.4	13.8	6.2	11.3	1.6	12.9	12.9
4 Noble Affiliates	0.5	16.3	6.2	12.9	0.5	13.5	13.5
5 Pogo Producing	0.5	15.4	6.2	12.3	0.5	12.9	12.9
AVERAGE	**0.7**	**16.5**	**6.2**	**13.0**	**0.8**	**13.8**	**13.8**

Notes:
Column 1: Value Line Investment Survey for Windows, 9/2001
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Column 3: Standard & Poor's DRI "The U.S. Economy: The 25-Year Focus"
Column 4 = Column 2 times 2/3 plus Column 3 times 1/3
Column 5 = Column 1 times (1 + Column 4/100)
Column 6 = Column 4 + Column 5
Column 7 = (Column 5 /0.95) + Column 4

TELECOMMUNICATIONS SERVICE COMPANIES
2-STAGE DCF: ANALYSTS' GROWTH FORECASTS

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	Proj GDP Growth (3)	Weighted Growth (4)	% Expected Divid Yield (5)	Cost of Equity (6)	ROE (7)
1 ALLTEL Corp.	2.3	12.2	6.2	10.2	2.6	12.8	12.9
2 AT&T Corp.	0.8	9.0	6.2	8.1	0.8	8.9	9.0
3 BellSouth Corp.	2.0	10.1	6.2	8.8	2.2	11.0	11.1
4 CenturyTel Inc.	0.6	11.1	6.2	9.5	0.6	10.1	10.1
5 Qwest Communic.	0.3	26.1	6.2	19.5	0.3	19.8	19.8
6 SBC Communications	2.5	10.6	6.2	9.1	2.7	11.8	11.9
7 Sprint Corp.	2.2	6.9	6.2	6.7	2.4	9.0	9.2
8 Telephone & Data	0.6	21.7	6.2	16.5	0.6	17.2	17.2
9 Verizon Communic.	3.1	9.5	6.2	8.4	3.3	11.7	11.9
AVERAGE	**1.6**	**13.0**	**6.2**	**10.7**	**1.7**	**12.5**	**12.6**
TRUNCATED AVERAGE							**12.1**

Notes:
Column 1: Value Line Investment Survey for Windows, 9/2001
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Column 3: Standard & Poor's DRI "The U.S. Economy: The 25-Year Focus"
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Column 5 = Column 1 times (1 + Column 4/100)
Column 6 = Column 4 + Column 5
Column 7 = (Column 5 /0.95) + Column 4

NATURAL GAS DIVERSIFIED COMPANIES
2-STAGE DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	Proj GDP Growth (3)	Weighted Growth (4)	% Expected Divid Yield (5)	Cost of Equity (6)	ROE (7)
1 Cabot Oil & Gas 'A'	0.7	10.0	6.2	8.7	0.8	9.5	9.5
2 Devon Energy	0.5	14.2	6.2	11.5	0.5	12.0	12.1
3 Dynegy Inc. 'A'	0.7	22.2	6.2	16.9	0.9	17.7	17.8
4 EOG Resources	0.5	13.1	6.2	10.8	0.6	11.4	11.4
5 El Paso Corp.	1.7	14.9	6.2	12.0	1.9	13.9	14.0
6 Enron Corp.	1.5	17.4	6.2	13.7	1.8	15.4	15.5
7 Equitable Resources	2.0	12.6	6.2	10.5	2.2	12.7	12.8
8 Kinder Morgan	0.4	21.6	6.2	16.5	0.4	16.9	16.9
9 Kinder Morgan Energy	5.9	11.9	6.2	10.0	6.5	16.5	16.9
10 Mitchell Energy 'A'	1.0	13.5	6.2	11.1	1.1	12.1	12.2
11 National Fuel Gas	4.2	11.4	6.2	9.7	4.6	14.3	14.5
12 Ocean Energy	0.8	25.4	6.2	19.0	1.0	20.0	20.0
13 Questar Corp.	3.2	11.4	6.2	9.7	3.5	13.2	13.4
14 TEPPCO Partners	6.6	8.6	6.2	7.8	7.1	14.9	15.3
15 Vintage Petroleum	0.9	16.7	6.2	13.2	1.0	14.2	14.3
16 Western Gas Res.	0.7	5.0	6.2	5.4	0.7	6.1	6.1
17 Williams Cos.	2.2	15.1	6.2	12.1	2.5	14.6	14.7
AVERAGE	**2.0**	**14.4**	**6.2**	**11.7**	**2.2**	**13.8**	**14.0**
TRUNCATED AVERAGE							**14.1**

Notes:
Column 1: Value Line Investment Survey for Windows, 9/2001
Column 2: Zacks Investment Research Web site, 9/2001
Column 3: Standard & Poor's DRI "The U.S. Economy: The 25-Year Focus"
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DOD/HECO-IR-3-14

[Morin Direct, p. 4, ll. 19-22]

Please provide a narrative description of Dr. Morin's understanding of the "Company's current energy cost adjustment clause," and how elimination of that adjustment clause would impact the Company's risk compared to other electric utilities that do not have such an adjustment clause.

Dr. Morin's Response:

Because of the Company's predominantly oil-based generating capacity, a dominant element of business risk peculiar to HECO is a significant consumption of fuel oil and the potential risks associated with variations in the price of oil. To illustrate, the fuel cost per barrel increased from $29 to $36 from 2002 to 2003. Mitigating this aspect of HECO's business risk is the Commission's continuation of an energy cost adjustment clause, decreasing the Company's risk of not recovering its substantial fuel costs.

The Energy Cost Adjustment Clause ("ECAC") serves to reimburse HECO for prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of energy costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. To illustrate, it is my understanding that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of ECAC, thus weakening the Company's financial integrity. The ECAC mitigates a portion of the risk and the absence of such protection would be factored into the Company's credit profile as a negative element which would in turn raises its cost of capital, as discussed above.

In the absence of the Commission renewal of the ECAC requested by HECO in this proceeding, HECO's financial condition would deteriorate, its credit ratings would likely be under review for possible downgrade, and its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for HECO. This situation would have a substantial effect on HECO and its customers because of the magnitude of the energy cost component in its cost of service.

Recovery of prudently incurred costs expended on energy allows a regulated utility to serve its native load customers in a reliable manner while maintaining its financial integrity or strength. Since the cost of energy is both a significant component of HECO's operations as well as variable over time, debt and equity investors consider the risks underlying these factors in their determinations as to whether to provide funding and upon what terms to a particular company.

DOD/HECO-IR-3-15

[Morin Direct, p. 10, l. 2]

a. Please define the phrase "attract capital on reasonable terms," that is, what is the dividing line between reasonable and unreasonable terms?

b. Please cite to the portion of <u>Hope</u>, <u>Bluefield</u>, <u>Memphis Light</u>, <u>Permian</u> or <u>Duquesne</u> that mentions or defines "reasonable terms."

<u>Dr. Morin's Response:</u>

a. The expression "reasonable terms" refers to the cost efficiency and comparability of terms on which capital is procured. The term "reasonable" means rational, sensible, in accord with common sense, acceptable, consistent with general prevailing capital market conditions. The term "reasonable" as employed by Dr. Morin in this context can also be interpreted to mean "within sensible limits of probability." It may also be interpreted as "terms" that are consistent with financial integrity. The latter is consistent with the maintenance of investment-grade credit ratings.

b. The relevant passages of the Bluefield, Hope, and Permian decisions dealing with the capital attraction standard are cited in italics on pages 9-10 of Dr. Morin's Direct Testimony. Dr. Morin notes the following citation from the Bluefield case:

> *"A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the*

DOD/HECO-IR-3-16

[Morin Direct, p. 12]

a. Does Dr. Morin believe the three cost of equity estimation methodologies on which he relies in this proceeding should be given equal weight in assessing the cost of equity for HECO? If so, why; if not, why not?

b. Has Dr. Morin consistently given the three methods (DCF, CAPM, and Risk Premium) equal weight in his testimony over the past 20 years? If not, please explain why not.

c. In his textbook, does Dr. Morin devote more chapters to the DCF, CAPM or Risk Premium? If one methodology garners more attention than the other two in Dr. Morin's textbook, please explain why.

<u>Dr. Morin's Response:</u>

a. Dr. Morin believes that equal weight should be accorded to the CAPM, Risk Premium, and DCF methodologies in determining the cost of capital. All three methodologies are discussed in college-level corporate finance textbooks, and all three are employed by practitioners, financial analysts, and most academicians. From a practical perspective, a survey of financial practices found that over 80% of corporations, financial advisers, and textbooks/tradebooks rely on the CAPM – Risk Premium methods to estimate the cost of equity as well as relying on the DCF approach[1].

As stated in Dr. Morin's direct testimony, no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single

Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others.

When measuring equity costs, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied across a series of comparable risk companies.

Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises which cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities. There is no guarantee that a single CAPM or Risk Premium result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single DCF result constitutes the perfect explanation of that stock price.

b. With very minor variations and under normal circumstances, Dr. Morin has consistently employed all three methodologies in the last twenty years in determining the cost of equity for U.S. regulated utilities.

c. The number of chapters or number of pages devoted to any one given methodology are certainly not indicative of the weight to be accorded to any one given method. However, it turns out that Dr. Morin's regulatory finance textbook does devote a reasonably equal amount of space to DCF (four chapters) and to Risk Premium methods, including the CAPM (five chapters).

Dr. Morin notes that most, if not all, college-level corporate finance textbooks devote the vast majority of their cost of capital coverage to asset pricing models, such as the CAPM, Fama-French version of the CAPM, and the Arbitrage Pricing Model. Considerably less attention is devoted to the DCF model in view of its limitations. See also Dr. Morin's comments on the DCF model in Chapter 9 of his text book "Reflections on Cost of Capital Methodology."

DOD/HECO-IR-3-17

[Morin Direct, p. 16, citing Brealey and Meyers]

a. Do Brealey and Meyers recommend using long-term Treasury Bonds as the risk-free rate in the CAPM?

b. If so, please provide a copy of the cover page and portion of their textbook in which they make that recommendation.

c. If not, please explain why Dr. Morin relies on Brealey and Meyers for authority in his Testimony in this proceeding.

Dr. Morin's Response:

a. & b. Brealey & Myers do not make a specific recommendation as to what specific risk-free proxy to employ to determine the cost of equity with the CAPM in regulatory proceedings. The Brealey & Myers corporate finance textbook is meant to be generic and applicable to the world of corporate finance in general rather than be specific to the regulated utility industry. Dr. Morin points out that Professor Myers has testified in many rate cases and for purposes of utility ratemaking, he has relied on long term rates. Professor Myers and his colleagues in the Brattle Group have filed numerous rate of return expert testimonies throughout North America and have relied on long term Treasury yields for purposes of employing the CAPM in utility ratemaking.

The important conceptual point is that the horizon of the selected Treasury bond match journal articles dealing with corporate finance generally and dealing with regulatory finance issues.

DOD/HECO-IR-3-18

[Morin Direct, p. 16, citing Phillips]

a. Does Dr. Phillips also comment on the reliability of the CAPM and Risk Premium methods?

b. If so, please provide those comments as well as Dr. Phillips comments on the DCF.

c. If so, please explain why Dr. Morin elected to include only Phillips comments regarding the DCF, and eliminate the other comments of a "leading expert in regulation."

Dr. Morin's Response:

a. Yes.

b. After consulting the Phillips text at the university library, Dr. Morin notes that the Phillips text deals with the reliability of the CAPM in a few paragraphs on pages 358-359.

c. Page 16 of Dr. Morin's testimony deals specifically with the dangers of relying on the DCF model and the lack of realism of its underlying assumptions when applied to the fast-changing electric utility industry. Dr. Morin is well aware that caution and judgment are required when relying on any model in the social sciences, including financial models such as the CAPM. Models represent simplified abstractions of reality so as to improve our understanding of socio-economic phenomena. In the case of financial models, the DCF model is particularly sensitive to fundamental and structural changes, for it assumes constant infinite growth in book value, earnings, dividends, and stock price forever.

DOD/HECO-IR-3-19

[Morin Direct, p. 17, ll. 20, 21]

a. Isn't it true that "several fundamental and structural changes have transformed the energy utility industry" since the CAPM was developed?

b. Please explain why Dr. Morin elected to single out the DCF in that regard.

Dr. Morin's Response:

a. Yes.

b. The DCF model is particularly sensitive to fundamental and structural changes, for it assumes constant infinite growth in book value, earnings, dividends, and stock price forever. The assumptions underlying the CAPM are far less stringent, however, and the model can accommodate structural changes in input parameters, such as beta. See also response to DOD/HECO-IR-3-18.

DOD/HECO-IR-3-20

[Morin Direct, p. 20]

a. Please provide a complete copy of one cost of capital testimony in which 1) Dr. Morin employs a CAPM analysis, 2) bond yields were projected to decline from then-current levels, and 3) Dr. Morin used the projected (lower) bond yield in his CAPM analysis.

b. Please provide one complete copy of a cost of capital testimony in which Dr. Morin did not undertake a CAPM analysis.

Dr. Morin's Response:

a. & b. Most, if not all, of Dr. Morin's cost of capital testimonies in the U.S. over the past decade, present the CAPM as the initial equity cost analysis, followed by the Risk Premium approaches, and the DCF methodologies.

DOD/HECO-IR-3-21

[Morin Direct, p. 20, ll. 6]

a. Please explain why Dr. Morin elected to use 30-year bond yields when the US Government no longer issues that type of security.

b. Are the Ibbotson historical return data based on 20-year Treasury bonds or 30-year bonds? Please provide support for your response.

Dr. Morin's Response:

a. In the same way that we can use stock prices in the application of the DCF model to a given company even though that company has not issued stock in the recent past, we can rely on bond prices of 30-year Treasury bonds and the implied yields. 30-year Treasury bonds are actively traded on secondary markets and provide useful price/yield signals.

b. Because 30-year bonds were not always traded or even available throughout the entire 1926-2003 long period covered in the Ibbotson Associate Study of historical returns, the latter study relied on bond return data based on 20-year [illegible]

DOD/HECO-IR-3-22

[Morin Direct, p. 20, ll. 20-24]

a. Does Dr. Morin agree that long-term Treasury bonds are usually priced to produce a yield higher than short-term Treasury securities?

b. Please explain why long-term Treasury bonds have higher yields than shorter-term Treasury securities.

c. Are risk and return directly or inversely related?

d. Please provide the evidence on which Dr. Morin bases the statement that "a substantial fraction of bond market participants....hold bonds until they mature."

Dr. Morin's Response:

a. Yes.

b. Generally, long-term Treasury bonds have higher yields than shorter-term Treasury securities because of the liquidity premium. There are time periods, however, where short-term securities have had higher yields than longer-term Treasury bonds. This "inverted yield curve" phenomenon is due to expectations of falling interest rates and/or market segmentation effects.

c. Risk and return are directly related.

d. A significant fraction of long-term bonds are held by institutional investors with long-term liabilities, such as pension funds, insurance companies, and leasing companies. One way for these institutional investors to immunize themselves against interest rate risk is to buy a pure discount bond with a maturity equal to their investment horizon and hold that bond until it matures. This works because there are no cash flows to reinvest and there is no price risk if the bond is held to maturity.

In the case of coupon bonds, this simple strategy has to be refined. It is still true that price risk is avoided if the bonds are held to maturity, but there remains reinvestment-rate risk since the coupons need to be reinvested at some unknown rate. Immunization is achieved by purchasing a coupon bond whose weighted maturity ("duration") is equal to the investment horizon. This works regardless of interest rate movements. If rates decrease, the investor is forced to reinvest coupons at lower rate but also makes a capital gain on the sale of the bonds at the end of the investment horizon. If rates increase, the capital loss on the sale at the horizon date is offset by the extra cash flow generated from investing the coupon payments a the new higher rate.

The case of pension funds is noteworthy. If the assets of a pension fund are invested in bonds, the duration (i.e. weighted maturity) of the assets can be computed. The duration of the obligations to retirees, analogous to interest payments on debt, can be calculated as well. Managers of pension funds therefore choose pension assets whose duration is matched with the duration of the liabilities. In this way, changing interest rates do not affect the net worth of the pension fund. In a similar fashion, insurance firms invest on bonds where the duration of the bonds is matched to the duration of the future death benefits.

DOD/HECO-IR-3-23

[Morin Direct, p. 22, 23]

a. Is Dr. Morin's risk-free rate based on a 30-year zero coupon yield rather than a constant maturity yield? If so, why; if not, why not?

b. Is the yield of a zero coupon bond normally higher or lower than a constant maturity bond of the same duration? Please explain why or why not.

Dr. Morin's Response:

a. As discussed in DOD/HECO-IR-22 (d) holding a zero coupon bond eliminates reinvestment risk and interest rate risk as well if held to maturity.

b. The 30-year yield on coupon-paying bonds has been virtually indistinguishable from the yield on the zero-coupon 30-year yield bonds. Whether a zero-coupon bond has a higher or lower yield than a coupon-paying bond of the same maturity is a function of investor expectations as to future interest rates (shape of the yield curve), that is, at what rate the coupons are to be reinvested. The important point is that when considering bonds with interim cash flows over the investment horizon, the total return is no longer a sure thing

Changing interest rates can cause the reinvested value of these interim payments to change. In the case of a zero-coupon bond, this problem can be avoided entirely, as no interim cash flows have to be reinvested, and the total return from holding a zero-coupon bond is a sure thing assuming the U.S. government makes the principal payment at maturity.

DOD/HECO-IR-3-24

[Morin Direct, p. 26, ll. 13-14]

a. Since Dr. Morin uses current and projected T-Bond yields as the risk-free rate in his CAPM, please explain why he did not use current and projected T-Bond yields to calculate a market risk premium.

b. If he had used current and projected T-Bond yields to calculate market risk premiums, would his CAPM results have been higher or lower? Please provide support for your response.

Dr. Morin's Response:

a. & b. Dr. Morin assumed that security returns move in unison. Since long-term yields generally move in unison, an increase (decrease) in the yield on long-term Treasury bonds will generally be accompanied by a parallel increase (decrease) in stock returns. As a result, the market risk premium is assumed to remain unchanged. Moreover, to the extent that the [redacted]

expect the equity risk premium to remain at its historical mean and not display trends.

DOD/HECO-IR-3-25

[Morin Direct, p. 26, f. 6]
Please provide a complete copy of the article cited.

Enclosed.

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Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM

Robert S. Harris, Felicia C. Marston, Dev R. Mishra, and Thomas J. O'Brien*

We estimate ex ante expected returns for a sample of S&P 500 firms over the period 1983-1998. The ex ante estimates show a better overall fit with the domestic version of the single-factor CAPM than with the global version, but the difference is small. This finding has no trend in time and is consistent across groups formed on the basis of relative foreign sales. The findings suggest that for estimating the cost of equity, the choice between the domestic and global CAPM may not be a material issue for many large US firms.

The estimation of a firm's cost of equity capital remains one of the most critical and challenging issues faced by financial managers, analysts, and academicians. Although theory provides several broad approaches, recent survey evidence reports that among large US firms and investors, the capital asset pricing model (CAPM) is by far the most widely used model.

Among the variety of decisions to be made in implementing the CAPM is the choice between a domestic or global index for the market portfolio. Although theory suggests that using a domestic market index is appropriate only for an asset traded in a closed, national market, empirical research has thus far failed to establish whether a global or domestic pricing model performs better with US stocks.

We study the choice between the global and domestic CAPM by examining which of the two models provides the better fit with a sample of *ex ante* expected equity return estimates for large US companies. In contrast to many prior studies that use realized returns, we estimate implied expected returns based on the theory's call for a forward looking measure. The question we ask is whether the domestic or the global version of the single-factor CAPM provides the better fit with the dispersion of the *ex ante* expected return estimates for a sample of S&P 500 equities. Our study period covers 1983 to 1998.

We find that the domestic US CAPM fits the *ex ante* expected return estimates better than does the global CAPM. This result shows no trend over time. We also find that except for a few years in the early 1990s, the better fit of the domestic CAPM holds consistently across subsamples formed on the basis of the relative levels of the firms' foreign sales. However, the difference in fit of the two versions of the CAPM is small.

We also find a positive and significant empirical relation between *ex ante* risk premium estimates and systematic risk estimates. Moreover, we find that the *ex ante* risk premium estimates for

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broad industry groups have a high correlation with the corresponding Fama-French (1997) estimates from the CAPM, but not with the estimates from their three-factor model.

The study's practical implications are based on the widespread use of the CAPM in cost of capital estimation by large US firms and investors, where the traditional use of the S&P 500 index as the "market portfolio" continues to be the standard. Our findings support the use of the domestic CAPM to estimate the cost of equity of large US firms. However, finding a relatively small difference in the overall fit of the two CAPM versions suggests that the choice between applying the domestic CAPM and the global CAPM may not be a critical issue for many large US firms.

The paper is organized as follows. Section I reviews related literature. This review includes the domestic and global versions of the single-factor CAPM and why the two models are theoretically likely to result in different expected rates of return for a given asset. Section II discusses the methodology and data for the empirical analysis. Section III reports the results of the empirical comparison of the *ex ante* expected return estimates with the estimates of the two CAPM versions and with corresponding measures of risk. Section IV provides a brief summary and conclusion.

I. Review of Related Literature

Recent survey evidence (Bruner, Eades, Harris, and Higgins, 1998) and Graham and Harvey, 2001) reports that the capital asset pricing model (CAPM) is widely used by large US firms and investors. The CAPM also continues to have wide popularity in academic textbooks and applied articles (e.g., Kaplan and Peterson, 1998 and Ruback, 2002).

These applications use the traditional domestic CAPM, $k_i = r_f + \beta_{iD}[k_{MD} - r_f]$; where k_i is the equilibrium expected rate of return for asset i; r_f is the risk-free rate; β_{iD} is the beta of asset i against the domestic market portfolio returns; k_{MD} is the equilibrium required rate of return on the domestic market portfolio; and $k_{MD} - r_f$ is the risk premium on the domestic market portfolio.

A. Global CAPM and Domestic CAPM

Stehle (1977) and Stulz (1995a, 1995b, 1999) argue that using a domestic market index is only appropriate for an asset traded in a closed, national financial market. Although equilibrium international asset pricing models are multifactor in general, if the purchasing power parity (PPP) condition holds, then the single-factor CAPM equation can be adapted to a international context for assets in the global market portfolio, as discussed in Stulz (1995c). We emphasize the difference between the domestic and global CAPMs by Equation (1).

$$k_i = r_f + \beta_{iG}[k_{MG} - r_f] \tag{1}$$

where k_i is the equilibrium expected rate of return for asset i in a specific pricing currency, r_f is the nominal rate of return on an asset that is risk-free and denominated in the pricing currency, β_{iG} is the beta of asset i's returns against the unhedged global market index returns, with returns computed in the pricing currency, k_{MG} is the equilibrium required rate of return in the pricing currency on the unhedged global market portfolio, and $k_{MG} - r_f$ is the risk premium on the unhedged global market portfolio. As in Grauer, Litzenberger, and Stehle (1976), under the assumption of logarithmic utility the global CAPM in Equation (1) holds with any numeraire currency. Ross and Walsh (1983) show that when log utility is not assumed, Equation (1) holds for at most one currency. We assume that currency is the US dollar.

Karolyi and Stulz (2003) point out that only in the special case in which β_{iG} equals $\beta_{iD}\beta_{DG}$ does the global CAPM result in the same expected return as the domestic CAPM, i.e., when an asset's global beta is equal to its domestic beta times the global beta of the domestic market portfolio. Generally, this condition does not hold. Instead, when β_{iG} is greater than $\beta_{iD}\beta_{DG}$, the domestic CAPM is likely to underestimate the asset's expected return relative to the global CAPM, because there is more global systematic risk in the asset's returns than is accounted for by the domestic market index. Similarly, when β_{iG} is less than $\beta_{iD}\beta_{DG}$, the domestic CAPM is likely to overestimate the asset's expected return relative to the global CAPM, because the asset has less global systematic risk in its returns than is accounted for by the domestic market index.

Stehle (1977) reports empirical support for the global CAPM over the domestic version in realized returns for US stocks from 1956 to 1975. Harvey's (1991) study provides further empirical support of global pricing of US equities. Black (1993) asserts that the issue of whether a global or domestic index should be used in CAPM applications is not yet settled. However, given the significant globalization of the world financial markets, Stulz (1995a, 1995b, 1999) advocates the use of the global version. In contrast to Stehle's (1977) findings, Griffin (2002) reports that for the period between 1981 and 1995, a three-factor (Fama-French) domestic model had lower pricing errors for US firms than did an analogous three-factor world version. His results indicate that a domestic pricing model is a better fit with realized return data than a global pricing model.

Campbell's (1996) empirical analysis of a multifactor domestic pricing model finds that the single-factor domestic "... CAPM is a good approximate model for stock and bond prices," since the additional factors (returns to human capital and changes in expected market return) are highly correlated with the market index returns. Ng (2003) reaches a similar conclusion in the context of the global CAPM, with the additional factors of FX risk and shifts in both expected market returns and expected FX changes. Therefore, we only examine the two single-factor CAPMs. Griffin (2002) does not report results on domestic compared to world single-factor (market index) models. However, in private correspondence after our study was completed, Griffin reported to us that the domestic version of the single-factor model had lower pricing errors than did the world model.

For large US companies like those in the S&P 500, there are arguments why choosing a domestic or a global index for CAPM applications could be a non-issue. One argument is that a US index will closely track a global index, especially as markets have become more integrated and since the market value of US stocks is a substantial proportion of the market value of a global index. However, the data show that the beta of the S&P 500 compared to the MSCI World Index has been substantially less than one in the past. Another argument is that S&P 500 companies are often global in scope, which makes the S&P 500 something of a global index in its own right. However, Jacquillat and Solnik (1978) and Christophe and McEnally (2000) report evidence that a portfolio of US multinationals is an ineffective vehicle for international diversification. Even if the choice between a global and a domestic index does not matter much for large US firms in general, it might make a difference for US firms with very high (or low) levels of foreign involvement. However, this empirical question is unanswered. Older studies by Hughes, Logue, and Sweeney (1975) and Agmon and Lessard (1977) suggest this possibility, reporting that global (domestic) betas increased (decreased) with the level of US firms' foreign-to-total sales ratio. However, more recent results in Diermeier and Solnik (2001) do not find this effect to be strong for US firms.

A domestic index could be the preferred benchmark for US investors with a significant "home bias", as in the Cooper and Kaplanis (2000) model of partially integrated world markets. However, we do not know whether the popularity of the domestic CAPM among US firms is for this reason.

B. *Ex Ante* Expected Return Estimates

Empirical tests comparing global to domestic pricing models usually rely on realized returns. However, Elton (1999) points out that *ex ante* estimates of expected returns are more desirable. We obtain *ex ante* expected return estimates through analysts' growth forecasts and discounted cash flow (DCF) models, as in a number of prior studies, including Claus and Thomas (2001), Fama and French (2002), and others discussed below.

In contrast to research that uses realized returns, almost all of the studies using *ex ante* expected return estimates find an empirical relation between expected return and beta risk, despite differences in approaches and time periods. For example, using the constant dividend growth model, Harris and Marston (1992) and Marston and Harris (1993) report a significant relation between *ex ante* expected return estimates and (domestic) betas for a sample of US stocks in the 1982-1987 period. At the same time they confirm the findings of previous empirical studies of no significant relation between realized returns and betas.

When they apply a DCF model to 51 highly leveraged transactions (mostly management buyouts) in the period 1980-1989, Kaplan and Ruback (1995) find that implied costs of capital estimates are related to beta but not to the size and book-to-market factors. Using IBES forecasts, Gordon and Gordon (1997) and Gode and Mohanram (2003) also observe a significant relation between *ex ante* expected equity return estimates and domestic US betas. Gordon and Gordon use a finite horizon dividend discount model and the time period 1985-1991. Gode and Mohanram use the Ohlson-Juettner (2000) valuation model for the period 1984-1998. Also, Brav, Lehavy, and Michaely (2003) find a positive empirical association between analysts' direct return forecasts and beta for US stocks, but not between the return forecasts and the size and book-to-market factors.

The results of Gebhardt, Lee, and Swaminathan (2001) provide the only exception that we know of to a positive empirical relation between *ex ante* expected return and beta risk estimates. Their study, which uses IBES forecasts and a clean-surplus residual income valuation model, reports no significant association between their *ex ante* expected return estimates and domestic betas for a sample of US stocks from the period 1979-1995.

There is some controversy about IBES forecasts. La Porta (1996) asserts that analysts' growth forecasts tend to be too extreme, but Lee, Myers, and Swaminathan (1999) find that IBES forecasts improve their intrinsic value estimates over forecasts based on a time series model.

II. Methodology and Data

In this section, we discuss our approach for estimating *ex ante* expected returns using the constant dividend growth model and the consensus of financial analysts' five-year earnings growth forecasts available through IBES. In addition, we explain our criteria for comparing the global and domestic CAPMs.

A. *Ex Ante* Expected Return Estimation

For each month from January 1983 through August 1998, we calculate an *ex ante* expected return estimate for each dividend-paying US stock in the S&P 500 index for which data are available. We eliminate a firm in a given month if there are fewer than three analysts' forecasts, if the standard deviation around the mean forecast exceeds 20%, or if there are not sufficient historical returns for the prior 60 months to perform beta estimations. The analysis comprises 65,154 expected return estimates for the months from January 1983 to August 1998. We obtain dividend and other firm-specific information from the Compustat files.

We estimate *ex ante* expected rates of return by using the constant dividend growth model.

$$k_i^a = \frac{D_{1i}}{P_{0i}} + g_i \qquad (2)$$

where k_i^a is the *ex ante* expected rate of return (cost of equity) estimate for company i, D_{1i} is the dividend per share expected to be received at time 1, P_{0i} is the current price per share, and g_i the expected long term growth rate in dividends per share, which we assume is equal to the consensus of the analysts' growth forecasts. See Timme and Eisemann (1989) for a review of the benefits of analysts' forecasts over historical growth estimates.

We recognize that our study, like any study of asset pricing relations, is a joint "test" of the underlying model and the empirical constructs used. Therefore, like other studies, we cannot conclude whether rejection is due to failure of the model or of the empirical proxies. With this standard caveat, our method for estimating *ex ante* expected returns, which uses IBES growth forecasts and the dividend growth model, has several strengths. First and ... measures of return should be those that investors expect to returns in US dollars from January 1978 through August 1998 from the CRSP files. We obtain T-bond returns from the website of the Federal Reserve Bank of St. Louis. We use the S&P 500 Index as the domestic US index. (We also use the CRSP Value-Weighted Index in a robustness check.) We use the Morgan Stanley Capital International (MSCI) World Index with gross dividend reinvestment as the global market index. The monthly data for the global index is from the website of MSCI: www.mscidata.com. This index is unhedged and thus, when reported in US dollars, reflects exchange rate changes in currencies against the US dollar.

The question we investigate is which of the two CAPM versions, if we assume that version is the "correct" model, has less variation in its fit with the *ex ante* expected return estimates for the individual firms. To implement this investigation, we "back out" the estimated *market* risk premia (domestic and global) for each month from the *ex ante* expected returns of the individual stocks. To do so, for a given month, we first turn each stock's *ex ante* expected return estimate into an *ex ante* risk premium estimate by subtracting the yield on the 20-year T-bond. Then we aggregate the stocks' *ex ante* risk premia estimates with value weighting, producing an *ex ante* portfolio risk premium estimate for the month. For the domestic CAPM, we value-weight the firms' domestic beta estimates into a portfolio domestic beta estimate for the month. Since the portfolio risk premium should be equal to the portfolio beta times the market risk premium, the domestic market risk premium estimate for the month is found implicitly by dividing the portfolio risk premium estimate by the portfolio domestic beta estimate. For example, if the value-weighted portfolio of eligible stocks has an *ex ante* risk premium estimate of 6% and a domestic beta estimate of 0.9, then the implicit domestic market risk premium estimate (for that month) is 6% divided by 0.9, which equals 6.67%. To ensure a fair comparison between the domestic CAPM (DCAPM) and the global CAPM (GCAPM), we use an analogous procedure (each month) to estimate the implicit global market risk premium from the *ex ante* portfolio risk premium estimate and the portfolio's global beta estimate. In other words, we estimate the domestic market risk premium by assuming that the domestic CAPM is valid for the average stock, and estimate the global market risk premium by assuming that the global CAPM is valid for the average stock. By design, this approach implies that the average difference between the model estimates and the *ex ante* estimates is zero for both CAPM versions.

We then investigate how much variation exists for individual firms between the *ex ante* risk premium estimates and the corresponding estimates of each of the two CAPM versions. For each month from January 1983 until August 1998, we analyze each available stock as follows. We begin by using the stock's domestic beta and the domestic market risk premium estimates to find the firm's risk premium estimate under the DCAPM. We also estimate the stock's risk premium under the GCAPM with the stock's global beta and the global market risk premium estimates. We then compare the *ex ante* risk premium estimate for the stock with the risk premium estimates of both CAPM versions.

For a given stock and month, there will generally be differences between all three risk premium estimates. For example, a stock in June 1989 might have an *ex ante* risk premium estimate of 5%, a DCAPM estimate of 4%, and a GCAPM estimate of 7%. In this hypothetical example, the DCAPM would be considered as the better fit because it provides a risk premium estimate that is closer to the *ex ante* estimate.

We use three metrics to assess which of the two CAPM versions has the better overall fit with the *ex ante* estimates. First, we examine the average of the absolute differences between the model estimates and the *ex ante* estimates. We decide that the model with the lower overall average of absolute differences across all observations for the individual firms is the better-fitting model for this metric. Second, we determine the percentage of the *ex ante* estimates for which the DCAPM provides a closer fit than the GCAPM. In the third metric, we compare the results of cross-sectional OLS of *ex ante* risk premium estimates for the individual stocks against both the estimated domestic betas and the estimated global betas. Whichever regression has the higher r-squared indicates the better-fitting CAPM version with this approach. We also examine the regression results for relative consistency with the theory: an intercept of zero and a positive slope.

Further, we investigate whether the fit of the *ex ante* estimates with those of the two CAPM versions is related to the ratio of foreign sales to total sales, which we use here as a proxy for international exposure. Although we understand that the relative level of foreign sales does not completely capture a firm's international exposure, its use is standard in many empirical studies, including Fatemi (1984), Jorion (1990), Miller and Reuer (1998), and Doidge, Griffin, and Williamson (2002), who contend that a good rationale for using relative foreign sales as a proxy for international exposure is the high correlation with other measures of firms' international operations.

Of the 489 firms used in the study, 253 firms have a reported foreign sales entry (including 76 firms reporting zero foreign sales) for the period 1994 to 1998. The overall average ratio of foreign to total sales is approximately 20% for the 253 firms. Using the eligibility criteria discussed above, we use the data for the 253 firms from 1983 to 1998 to construct a subsample of 36,580 observations (out of the 65,154 total observations), an average of about 194 firms per month. Of these observations, 11,053 involve a firm reporting zero foreign sales during 1994-1998, an average of about 59 firms per month. We divide the remaining observations, involving firms reporting non-zero foreign sales during 1994-1998, into three equal-sized groups of 8,509 observations based on the magnitude of relative foreign sales. Each group had an average of about 45 firms per month. The high foreign sales group has an average ratio of foreign to total sales of 53%, and the medium and low groups had ratios of 27% and 7%, respectively.

III. Results

This section describes in detail the results of the study, as reported in the tables.

A. Summary of Risk Premium Differences for DCAPM and GCAPM

Table I summarizes the average absolute differences between the *ex ante* risk premium estimates and the DCAPM and GCAPM estimates, and the percentage of instances in which the *ex ante* estimates are closer to the DCAPM estimate than to the GCAPM estimate. For all the observations in the sample, over all years from 1983 through 1998, the DCAPM's estimated expected return differs in absolute terms from the corresponding *ex ante* estimate by an average of 0.027, or 270 basis points. The GCAPM's estimated expected return differs in absolute terms from the corresponding *ex ante* estimate by an average of 0.029, or 290 basis points.

For every year except 1992, the average absolute difference between the DCAPM estimates and the *ex ante* estimates is less than or equal to the average absolute difference between the GCAPM estimates and the *ex ante* estimates. Based on the average absolute difference criterion, we find that the DCAPM has a better overall fit with the *ex ante* risk premium estimates.

However, the overall margin of difference, 270 basis points compared to 290 basis points, is not dramatic. The difference is the closest in the early 1990s. In contrast, in the 1980s and late 1990s, the DCAPM is the better fit by a wider margin. In a robustness check, we obtain

Table I. Summary of Risk Premium Differences For DCAPM and GCAPM

The columns show, respectively, the average number of firms per month (#Firms), the value-weighted averages of the estimated *ex ante* risk premia (*Ex Ante*), average domestic beta estimates (β_{iD}), the average domestic market risk premium estimates (RP_D), the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), the average global beta estimates (β_{iG}), the average global market risk premium estimates (RP_G), the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are corresponding *t*-statistics.

Year	#Firms	*Ex Ante*	β_{ID}	RP_D	*Ex*-D	β_{IG}	RP_G	*Ex*-G	%DCAPM Closer
1983	285	0.066	0.883	0.075	0.030	0.864	0.077	0.031	0.573(8.489)***
1984	300	0.053	0.915	0.058	0.026	0.897	0.059	0.027	0.581(9.777)***
1985	314	0.057	0.925	0.062	0.026	0.915	0.062	0.028	0.561(7.524)***
1986	320	0.074	0.985	0.075	0.028	0.890	0.084	0.030	0.580(9.931)***
1987	327	0.061	1.024	0.060	0.024	0.941	0.065	0.027	0.618(14.76)***
1988	335	0.064	1.000	0.064	0.024	0.969	0.066	0.026	0.589(11.28)***
1989	352	0.066	0.982	0.067	0.023	0.890	0.073	0.025	0.601(13.08)***
1990	357	0.071	0.972	0.073	0.025	0.797	0.089	0.026	0.531(4.108)***
1991	363	0.075	0.976	0.077	0.027	0.723	0.104	0.027	0.482(-2.409)**
1992	370	0.078	0.990	0.079	0.030	0.723	0.109	0.028	0.440(-8.002)***
1993	374	0.082	1.018	0.080	0.029	0.576	0.142	0.029	0.490(-1.299)
1994	375	0.073	1.038	0.070	0.025	0.576	0.126	0.026	0.515(2.012)**
1995	370	0.077	1.039	0.074	0.028	0.579	0.133	0.031	0.538(5.118)***
1996	379	0.078	1.008	0.077	0.027	0.604	0.129	0.035	0.632(17.83)***
1997	383	0.082	1.005	0.081	0.029	0.650	0.127	0.037	0.616(15.73)***
1998	388	0.092	1.010	0.091	0.031	0.793	0.116	0.035	0.575(7.826)***

B. Cross-Section Regressions On Systematic Risk

Table II reports the results of the cross-section regression of the firms' *ex ante* risk premium estimates on the beta estimates. Overall, the cross-section regressions provide further evidence that consistently throughout the time period 1983-1998, the *ex ante* estimates have a better fit with those of the DCAPM than with the GCAPM. Table II shows that the r-squares of all of the regressions are higher when we use the domestic beta as the independent variable than with the global beta. Moreover, the DCAPM regression results are consistently better aligned with the theory. The regression intercepts are closer to zero for the DCAPM than for the GCAPM, and the *t*-statistics on the slope coefficients are more significant for the DCAPM than for the GCAPM. These observations apply to the entire period, to all four individual sub-periods, and to each of the 16 years covered in the study.

The findings of significant, positive slope coefficients in each of the 16 years' cross-section regressions appear to strongly confirm the basic asset pricing theory prediction that expected returns are positively related to beta risk. We note that we are using individual stock parameters, not portfolios, and we use no control variables in the cross-section regressions. However, the positive regression intercepts suggest the possible omission of risk factor(s) or systematic optimism in the analysts' growth forecasts. Further exploration of this issue is beyond the scope of this study and is a topic for future research.

Together, Tables I and II lead us to conclude that using all three metrics (average absolute differences, percentage of cases with the better fit, and cross-section regression results), the domestic CAPM fits the dispersion of *ex ante* risk premium estimates better than does the global CAPM. This finding surprised us, in light of the continuing integration of world financial markets and international diversification by investors. However, this finding is consistent with the Cooper and Kaplanis (2000) model of partially segmented global capital markets and home bias.

C. Impact of Foreign Sales

We hypothesize that the global CAPM provides the better fit for companies with a relatively higher level of foreign sales, or that at least we observe a trend toward this relation over time. Table III shows this expectation is not the case. Only in the 1990-1994 period the GCAPM is the better fit for the high and medium foreign sales groups, and the DCAPM is the better fit for the low and zero foreign sales groups. However, after 1994, the pattern is generally the same for all four foreign sales groups, and there is no longer a better fit by the GCAPM for firms in the high and medium relative foreign sales groups.

Looking at all the years together, the average absolute differences between the *ex ante* risk premium estimates for the individual stocks and those of the two CAPM versions are about the same for each foreign sales level group, and the DCAPM estimates are slightly closer to the *ex ante* estimates in all four groups. Thus, we conclude that the relative level of foreign sales does not indicate when the *ex ante* expected returns are more closely related to the GCAPM than the DCAPM, except possibly during times when the US and global economies are not in sync.

D. Risk Premium Estimates and Differences by Industry

Given the potential for measurement error at the company level, there are benefits from looking at industry aggregates. Table IV breaks down the full-period risk premium estimates by broad industry groups. The results weight each firm in the industry equally. We obtain similar results

Table II. Cross-Section Regressions

The table presents the results of cross-section regressions of *ex ante* risk premium estimates and systematic risk estimates for [illegible]

Table III. Impact of Foreign Sales

The table displays the results of our analysis of the average absolute risk premium differences for individual firms for four groups, sorted by the ratio of foreign sales to total sales. The average ratio of foreign-to-total sales for the HIGH (MEDIUM, LOW) Foreign Sales Group is 53% (28%, 7%), respectively. Each group shows three columns, the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are corresponding *t*-statistics.

	High Foreign Sales			Medium Foreign Sales		
Year	***Ex*-D**	***Ex*-G**	**%DCAPM Closer**	***Ex*-D**	***Ex*-G**	**%DCAPM Closer**
1983	0.025	0.029	0.707(9.76)***	0.029	0.031	0.585(3.73)***
1984	0.021	0.024	0.723(10.69)***	0.027	0.028	0.620(5.36)***
1985	0.021	0.023	0.571(3.14)***	0.027	0.027	0.513(0.58)
1986	0.023	0.026	0.613(5.14)***	0.028	0.029	0.517(0.72)
1987	0.021	0.022	0.605(4.75)***	0.027	0.029	0.574(3.47)***
1988	0.023	0.024	0.561(2.76)***	0.027	0.028	0.560(2.84)***
1989	0.023	0.024	0.571(3.30)***	0.026	0.028	0.555(2.65)***
1990	0.024	0.024	0.476(-1.12)	0.028	0.027	0.519(0.89)
1991	0.031	0.030	0.443(-2.71)***	0.028	0.028	0.549(2.33)**
1992	0.029	0.026	0.353(-7.38)***	0.029	0.029	0.487(-0.62)
1993	0.028	0.024	0.405(-4.74)***	0.032	0.030	0.525(1.22)
1994	0.024	0.020	0.409(-4.55)***	0.027	0.024	0.499(-0.04)
1995	0.027	0.028	0.464(-1.79)*	0.026	0.029	0.544(2.058)**
1996	0.022	0.032	0.664(8.50)***	0.025	0.040	0.702(10.42)***
1997	0.025	0.037	0.664(8.57)***	0.025	0.047	0.788(16.91)***
1998	0.026	0.034	0.627(5.28)***	0.029	0.041	0.749(11.44)***
Average	0.025	0.027	0.546(8.55)***	0.028	0.031	0.578(14.51)***
	Low Foreign Sales			**Zero Foreign Sales**		
Year	***Ex*-D**	***Ex*-G**	**%DCAPM Closer**	***Ex*-D**	***Ex*-G**	**%DCAPM Closer**
1983	0.036	0.036	0.499(-0.04)	0.027	0.029	0.518(0.88)
1984	0.029	0.028	0.530(1.27)	0.025	0.026	0.54(2.01)**
1985	0.028	0.030	0.639(6.31)***	0.029	0.031	0.585(4.48)***
1986	0.032	0.032	0.532(1.41)	0.028	0.032	0.649(8.11)***
1987	0.027	0.027	0.579(3.59)***	0.026	0.031	0.682(10.27)***
1988	0.025	0.026	0.511(0.49)	0.024	0.027	0.611(6.01)***
1989	0.026	0.027	0.579(3.82)***	0.022	0.024	0.579(4.19)***
1990	0.027	0.028	0.559(2.80)***	0.026	0.027	0.482(-0.97)
1991	0.025	0.027	0.533(1.59)	0.026	0.025	0.414(-4.66)***
1992	0.029	0.030	0.526(1.24)	0.026	0.025	0.484(-0.85)
1993	0.030	0.031	0.542(2.04)**	0.026	0.032	0.551(2.80)***
1994	0.025	0.024	0.503(0.17)	0.024	0.029	0.57(3.92)***
1995	0.026	0.027	0.506(0.29)	0.031	0.036	0.634(7.55)***
1996	0.026	0.027	0.554(2.66)***	0.033	0.040	0.611(6.19)***
1997	0.027	0.031	0.557(2.80)***	0.034	0.038	0.534(1.89)*
1998	0.030	0.032	0.512(0.49)	0.033	0.033	0.526(1.22)
Average	0.028	0.029	0.541(7.67)***	0.027	0.030	0.561(12.99)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.
*Significant at the 0.10 level.

Table IV. Risk Premium Estimates and Differences by Industry

The table shows the breakdown of the full-period risk premium estimates by broad industry groups. The reported results weight each firm in the industry equally. Columns two to nine, respectively, show the total number observations (#Obs), the average *ex ante* risk premia (*Ex Ante*), the average domestic beta estimates (β_{iD}), the average global beta estimates (β_{iG}), the average DCAPM industry risk premium estimate (RP_D), the average GCAPM industry risk premium estimate (RP_G), the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), and the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are the corresponding *t*-statistics. Rows in italics indicate *Ex*-G lower than *Ex*-D.

Industry	#Obs	Ex Ante	β_{iD}	β_{iG}	RP_D	RP_G	Ex-D	Ex-G	%DCAPM Closer
Aero	738	6.63	1.15	0.90	7.86	7.97	0.031	0.033	0.52(0.96)
Autos	1546	5.29	1.15	0.89	7.94	7.69	0.033	0.037	0.54(3.52)***
Banks	4004	7.16	1.21	0.85	8.58	7.96	0.027	0.026	0.49(-0.82)
Beer	1264	6.60	0.87	0.69	6.07	6.25	0.024	0.028	0.64(10.25)***
BldMt	1298	6.84	1.27	1.01	8.74	8.51	0.026	0.029	0.64(10.84)***
Books	1291	7.64	1.07	0.80	7.37	6.86	0.021	0.023	0.52(1.48)
Boxes	626	8.39	1.04	0.85	7.15	7.27	0.027	0.029	0.52(1.04)
BusSv	1374	8.15	1.07	0.82	7.49	7.24	0.023	0.028	0.60(7.77)***
Chems	2451	6.49	1.16	0.94	7.99	8.14	0.024	0.026	0.57(7.50)***
Chips	1414	8.11	1.28	0.96	8.93	8.53	0.026	0.028	0.57(5.70)***
Clths	562	7.74	1.37	0.93	9.69	8.74	0.030	0.030	0.47(-1.44)
Cnstr	*989*	*7.70*	*1.54*	*1.18*	*10.68*	*10.33*	*0.046*	*0.039*	*0.39(-7.14)****
Comps	*1281*	*9.42*	*1.19*	*0.90*	*8.31*	*8.09*	*0.032*	*0.037*	*0.53(2.27)***
Drugs	2098	8.29	0.99	0.78	6.91	7.09	0.023	0.023	0.50(0.00)
ElcEq	1246	6.89	1.08	0.89	7.46	7.63	0.017	0.019	0.55(3.65)***
Energy	3487	6.29	0.88	0.87	5.99	7.63	0.032	0.035	0.57(8.12)***
Fin	657	8.38	1.76	1.13	12.87	11.89	0.056	0.053	0.49(-0.74)
Food	*2588*	*7.02*	*0.86*	*0.65*	*5.99*	*5.77*	*0.019*	*0.025*	*0.69(20.71)****
Fun	183	9.98	1.19	0.95	8.25	8.40	0.020	0.018	0.33(-4.78)***
Gold	588	4.59	0.57	0.85	3.76	7.48	0.050	0.051	0.61(5.50)***
Hlth	432	10.4	1.29	1.05	8.99	9.83	0.026	0.024	0.49(-0.48)
Hshld	2368	6.77	1.02	0.77	7.10	6.92	0.021	0.022	0.51(1.11)
Insur	4992	7.46	1.03	0.72	7.23	6.45	0.024	0.024	0.51(1.95)*
LabEq	1280	7.31	1.10	0.92	7.48	7.92	0.020	0.020	0.48(-1.40)
Mach	*2683*	*7.32*	*1.20*	*0.98*	*8.36*	*8.86*	*0.027*	*0.032*	*0.57(7.75)****
Meals	561	7.98	1.06	0.79	7.35	7.18	0.024	0.028	0.63(6.53)***
MedEq	1334	8.80	1.03	0.77	7.18	6.86	0.029	0.032	0.52(1.70)*
Paper	2969	6.14	1.13	0.89	7.79	7.59	0.024	0.025	0.59(9.48)***
PerSv	453	9.12	0.95	0.76	6.61	6.95	0.028	0.028	0.58(3.28)***
Retail	*4380*	*9.27*	*1.12*	*0.76*	*7.74*	*6.65*	*0.031*	*0.038*	*0.62(16.24)****
Rubber	524	7.06	1.22	0.88	8.55	8.14	0.025	0.027	0.55(2.19)**
Ships	187	1.95	0.95	0.65	6.39	4.75	0.046	0.041	0.27(-6.98)***
Stee	1510	4.96	1.13	0.97	7.76	8.18	0.041	0.044	0.61(8.92)***
Telcm	1553	6.12	0.83	0.61	5.91	6.08	0.020	0.023	0.56(4.42)***
Toys	*447*	*7.42*	*1.24*	*0.93*	*8.70*	*8.54*	*0.028*	*0.035*	*0.69(8.63)****
Trans	1651	5.70	1.14	0.87	7.90	7.67	0.029	0.031	0.50(0.37)
Txtls	374	6.52	0.95	0.74	6.50	6.53	0.022	0.024	0.58(3.14)***
Util	6189	4.15	0.57	0.48	3.95	4.38	0.017	0.019	0.57(10.79)***
Whlsl	1582	8.29	0.92	0.75	6.41	6.77	0.028	0.025	0.45(-4.40)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.
*Significant at the 0.10 level.

with value weighting. Also, the DCAPM industry risk premium estimates with the CRSP Value-Weighted Index are very close to the estimates we report for the S&P 500 Index.

Since the DCAPM provides the better overall fit, the DCAPM will have the better fit for many industries. The GCAPM provides a slightly better fit for a few of the industry groups, Banks, Construction, Finance, Health, and Wholesale. For industry groups such as Computers, Food, Machines, Retail, and Toys, the DCAPM provides a significantly better overall fit with the *ex ante* estimates than does the GCAPM.

E. Further Analysis of Industry Risk Premium Estimates

Table V reports the results of cross-section regressions using the industry risk premium estimates for the period 1983-1998, and estimates obtained from other approaches by Fama and French (1997) and Gebhardt et al. (2001). We excluded the Ships and Fun industries, which only had one firm each in our sample.

The most striking result in Table V is that the *ex ante* industry risk premium estimates have an r-square of 31.6% (a correlation of about 0.56) with the Fama-French DCAPM estimates. The Fama-French DCAPM industry estimates even outperform our own DCAPM industry estimates in explaining our *ex ante* industry estimates, even though the Fama-French time span is different, 1963-1994. Perhaps the explanation has to do with investors using more than five years of realized returns as the basis for expectations, or viewing the one-month Treasury bill (used by Fama and French) as the risk-free security instead of the 20-year T-bond used in this study. Both of the DCAPM industry estimates outperform the GCAPM industry estimates.

The r-square of the *ex ante* industry risk premium estimates and the Fama-French (1997) industry risk premium estimates for the 3-Factor Model is only 5.79% (a correlation coefficient of 0.24). Thus, the *ex ante* industry risk premium estimates have a much better fit with the Fama-French DCAPM industry estimates than with those of the 3-Factor Model. This finding is consistent with similar findings reported by Kaplan and Ruback (1995) and Brav et al. (2003). The results with the CRSP Value-Weighted Index as the DCAPM benchmark are very close to those reported with the S&P 500 Index.

Gebhardt et al. (2001) determined their *ex ante* risk premium estimates by using the residual income model from the full period 1979-1995, with the ten-year T-bond serving as the risk-free security. The Gebhardt-Lee-Swaminathan industry risk premium estimates have a very low correlation with our DCAPM and GCAPM estimates, with the Fama-French (1997) DCAPM and 3-Factor Model estimates, and with our *ex ante* industry estimates.

IV. Conclusion

We compare *ex ante* expected return estimates, which are implicit in share prices, analysts' growth forecasts, and the dividend growth model, with expected return estimates from the global CAPM and the domestic (US) CAPM. We use the MSCI World Index as the market benchmark for computing betas for the global CAPM, and both the S&P 500 Index and the CRSP Value-Weighted Index as the market benchmark for computing betas for the domestic

Table V. Cross-Section Regressions with Industry Risk Premium Estimates

Panel A displays the results of cross-section regressions. We use our industry *ex ante* risk premium estimates for the period 1983-1998 compared to industry average risk premium estimates from the DCAPM, the GCAPM, and estimates reported in Fama and French (1997) and Gebhardt, Lee, and Swaminathan (2001). Panel B shows the results of cross-section regressions using the Gebhardt, Lee, and Swaminathan (2001) *ex ante* risk premium estimates (from the residual income model for the overall time period 1979-1995) compared to industry average risk premium estimates from the DCAPM, the GCAPM, and estimates reported in Fama and French (1997). The numbers in parenthesis are the corresponding t-statistics.

Independent Variable	Intercept	Slope	R- Square
Panel A. Dependent Variable: Ex Ante Industry Risk Premium Estimate			
Industry Risk Premium Estimates:			
--Our DCAPM	4.442(4.51)***	0.370(2.92)***	19.58%
--GCAPM	4.775(3.73)***	0.325(1.96)**	9.99%
--Our Fama-French DCAPM	2.861(2.58)***	0.773(4.02)***	31.60%
--Fama-French 3-Factor	8.218(11.86)***	-0.154(-1.47)	5.79%
--Gebhardt-Lee-Swaminathan	7.241(17.03)***	0.005(0.04)	0.00%
Panel B. Dependent Variable: Industry Risk Premium Estimate of Gebhardt-Lee-Swaminathan			
Industry Risk Premium Estimates:			
-- Our DCAPM	0.863(0.65)	0.237(1.38)	5.13%
-- Our GCAPM	2.287(1.36)	0.050(0.23)	0.15%
-- Fama-French DCAPM	1.305(0.79)	0.240(0.83)	1.93%
-- Fama-French 3-Factor	1.343(1.56)	0.212(1.62)	6.97%

***Significant at the 0.01 level.
**Significant at the 0.05 level.

cost of equity, the choice between the domestic and global CAPM may not be a material issue for many large US firms.

The consistently better performance of the domestic CAPM surprises us, given the extensive integration in the world financial markets and arguments for the global CAPM over the domestic CAPM. Perhaps the explanation is that US practitioners apply the domestic CAPM, as suggested in standard textbooks when they should be using the global CAPM. An alternative explanation is that US practitioners believe a domestic market index is a better benchmark for their investment decisions than is a global index. By extending our study to smaller US companies and to non-US companies, we might be able to shed more light on this question. We leave this possibility to future research.

We also find significant and consistently positive associations between our *ex ante* risk premium and beta estimates. These findings are consistent with the reports in a number of other studies that use *ex ante* return estimates.■

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DOD/HECO-IR-3-26

[Morin Direct, p. 27]

Are the risk premiums cited on page 27 based on market index returns or on utility stock returns? Please cite to evidence from the Harris and Marston article to support your response.

Dr. Morin's Response:

The market risk premiums cited on Page 27 are based on aggregate market index returns and not on utility returns. See response to DOD/HECO-IR-25.

DOD/HECO-IR-3-27

[Morin Direct, p. 28, l. 6]

a. Please list the research papers cited by Dr. Morin that use unadjusted, or "raw", betas and list the papers which use betas adjusted in the manner used by Value Line. Please provide complete copies of the studies that rely on adjusted betas.

b. One of the sources cited in Chapter 13 of Dr. Morin's text is Dr. Morin's rebuttal testimony in a March 1989 US West Communications (Mountain Bell) proceeding before the Arizona Corporation Commission. Please provide a complete copy of that testimony.

Dr. Morin's Response:

a. To the best of Dr. Morin's knowledge, most of the empirical studies cited at the end of Chapter 13 of the 1994 edition of Regulatory Finance utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. Merrill Lynch adjusted betas and Bloomberg adjusted betas were not available during that period. Value Line adjusted betas were utilized in the later studies performed by Dr. Morin and discussed in HECO-2011.

b. See pages 2 to 30 of this response.

Arizona Corporation Commission

US West Communications - Appendix B

Rebutal Testimony of Dr. Roger A. Morin

March 28, 1989

APPENDIX B

THE RELATIONSHIP BETWEEN RISK AND RETURN

This appendix is divided into three segments. In the first segment, I describe the Capital Asset Pricing Model (CAPM) and address the implementation problems associated with each component of the CAPM. In the second segment, I demonstrate that the traditional Sharpe-Lintner version of the CAPM produces biased estimates of equity costs, and that the relationship between return and risk should be estimated empirically through the empirical form of the CAPM. (ECAPM). In the third section, I empirically derive a risk-return relationship for illustrative purposes, and propose a workable approximation to the observed risk-return relationship.

I. THE CAPM AND ITS COMPONENTS

A brief description of the CAPM is necessary at the outset. The conceptual underpinnings of the CAPM, a description of the underlying assumptions, and the formal derivation of the CAPM can be found in Morin, R.A. Utilities Cost of Capital, Public Utilities [illegible]

The fundamental idea underlying the CAPM is that risk-averse investors demand only market risk matters, as measured by beta. Securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

= RISK-FREE RATE + RELEVANT RISK x MARKET PRICE OF RISK

For a diversified investor, the only relevant risk is that which cannot be eliminated by diversification, that is, market risk or BETA. Therefore,

EXPECTED RETURN = RISK-FREE RATE + BETA x MARKET PRICE OF RISK

$$K = R_F + \text{BETA}(R_M - R_F) \qquad (1)$$

Equation (1) is the seminal CAPM expression. The CAPM asserts that an investor expects to earn a return, K, that could be gained on a riskless investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, BETA, and the market price of risk, $R_M - R_F$.

Despite the conceptual appeal and mechanistic simplicity of the model, actual implementation of the model to estimate a fair return on equity presents practical difficulties. From the start, the CAPM model and its variants are expectational models (as with most valuation models in finance), while only historical data are available to match the theoretical input variables: expected risk-free return, expected beta, and expected market return. To stress this point, the following equation restates the CAPM formula with expectational operators attached to each input variable:

$$E(K) = E(R_f) + E(B) \times [E(R_M - E(R_f)] \qquad (2)$$

where $E(K)$ = expected return, or cost of capital

$E(R_f)$ = expected risk-free rate

$E(B)$ = expected beta

$E(R_M)$ = expected market return

None of the input variable exists as separate identifiable entities. It is thus necessary in practice to employ proxies, obtaining different results with each set of proxy variables.

I. (1) Risk-Free Rate

The best surrogate for the risk-free rate is the yield on default-free long-term Treasury bonds. The use of one-year [illegible] equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of one year. More importantly, short-term Treasury Bills yields reflect the impact of factors different from those influencing long-term securities such as common stock. The premium for expected inflation impounded into short-term Treasury Bills is likely to be far different than the inflationary premium impounded into long-term securities yields. On grounds of consistency alone, the yields on default-free long-term Treasury bonds match more closely with common stock returns and are more appropriate. In my CAPM analyses, I use the current yield on long-term Treasury bonds as an estimate of the risk-free rate. Alternatively, an average of the yields on Treasury bonds futures contracts extending out 2 years in maturity could be used.

I.(2) BETA ESTIMATE

The true beta of a security ...

the true expected growth rate in the DCF model can never be observed.

return data going as far back as possible. But the company's risk may have changed if the historical period is too long. Weighting the data for this tendency is one possible remedy, but this presupposes some knowledge on how risk changes. A frequent compromise is to use a five-year period with either weekly or monthly returns. Value Line betas are computed based on weekly returns over a five-year period using the New York Stock Exchange Stock Index; Merrill Lynch betas are computed with monthly returns over a five-year period using the Standard & Poor's 500 Industrials Index.

By construction, backward-looking betas are sluggish in detecting fundamental changes in a company's risk, even when estimated over sufficiently long periods using weekly or monthly returns. For example, if a utility suddenly increases its business risk or its debt to equity ratio, one would expect an increase in beta. However, if 60 months of return data are used to estimate beta, only one of the 60 data points reflects the new information, one month after the utility increased its risk level. Thus, the change in risk only has a minor effect on the historical beta. Even one year later, only 12 of the 60 return points reflect the event. Therefore, care must be taken when using historical betas for a company which has experienced a recent structural shift in fundamentals.

I. (3) MARKET RISK PREMIUM

The last required input to the CAPM is the expected risk premium on the

[redacted]

The first method is to estimate the market return R_M, directly and then subtract R_f; the second is to estimate directly the market risk premium, $R_m - R_f$, as a whole. To estimate the latter, either historical risk premium results or expectational results can be used. In the case of historical risk premium results, it is assumed that investors anticipate about the same risk premium in the future as in the past.

The direct estimation of R_M can be achieved by applying the DCF methodology to a representative market index, such as the Standard & Poor's 500, Value Line Composite, or the New York Stock Exchange Index. For reasons of consistency, the market index employed should be the same as the market index used in deriving estimates of beta. A standard DCF with a 10-day average index value, an expectational dividend yield on the index adjusted for quarterly timing, and an aggregate composite growth estimate based on analysts' forecast, such as the composite 5-year earnings growth forecast in

[redacted]

IBES, or Zacks' ICARUS data bases, could accomplish this.

Historical return data for common equities and bonds are compiled, and the historical mean return differential between stocks and bonds serves as the measure of risk premium. The historical return data typically originates from the landmark Ibbotson-Sinquefield [Stocks, Bonds, Bills, and Inflation: The Past and the Future, Charlottesville, Va: Financial Analysts Research Foundation, 1982, Monograph #15] study, which compared realized holding period annual returns on equities, government long-term and short-term securities, corporate bonds, and inflation from 1926 to 1982. Annual updates of the return results are published by Ibbotson-Sinquefield. Application of the method proceeds directly from the historical results. It is imperative that if historical risk premiums are to be relied upon, they be estimated over very long time periods. Only over long periods do investor expectations and realizations converge, or otherwise investors would not commit investment capital. Investor expectations are eventually revised to match historical realizations, as market prices adjust to bring anticipated and actual investment results into equilibrium.

One further issue relating to the use of realized returns is whether to use the arithmetic mean or the geometric mean return. Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital. This is formally shown by Brealey & Myers ["Principles of Corporate Finance," Instructors' Manual, Appendix C, McGraw Hill 1984] and in Ibbotson Sinquefield, op. cit..

According to the 1987 edition of the Ibbotson-Sinquefield report, the average return on stocks in the 1926-1986 period was 12.1%, while the return on long-term [illegible]

premium of 7.4% for the average stock. The latter estimate can be used as an alternative to the direct expectational approach previously described.

II. THE EMPIRICAL CAPM

II. (1) EMPIRICAL VALIDATION OF THE SHARPE-LINTNER CAPM

There have been countless empirical tests of the Sharpe-Lintner CAPM to determine to what extent security returns and betas are related in the manner predicted by the Sharpe-Lintner CAPM. The results of these exhaustive tests, including those reported in the next section, support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the empirical risk-return relationship is not as steeply sloped as the predicted relationship. That is, low-beta securities earn returns somewhat higher than

The empirical evidence also demonstrates that the return-beta relationship is unstable over short periods, and differs significantly from the long-run relationship. This evidence underscores the potential for error in cost of capital estimates which apply the CAPM using historical data over short time periods.

In short, the currently available empirical evidence indicates that the simple version of the CAPM does not provide a complete description of the process determining security returns. Reasons advanced for the inadequacies of the Sharpe-Lintner CAPM include the following:

1. Due to intertemporal effects not considered in the single-period CAPM, other sources of uncertainty besides market risk are significant in portfolio choice.[1]

2. Constraints on investor borrowing exist contrary to the assumption of the CAPM.

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1 For a summary of intertemporal CAPM theory and supporting evidence, see Morin, R. A. "Multiperiod Asset Pricing Theory: An empirical Test." Financial Management Association Meeting Oct. 1987, Center for the Study of Regulated Industry, Georgia State University, Working Paper 87-3.

3. The CAPM excludes other important variables which are important in determining security returns. Factors other than beta influence investor behavior, such as taxes and size.

4. The market index typically used in the empirical tests exclude important classes of securities, such as bonds, mortgages, and business investment.

II. (2) CAPM EXTENSIONS

Expanded CAPM models have been proposed which relax some of the more restrictive assumptions underlying the Sharpe-Lintner CAPM, and which enrich its conceptual validity. These expanded CAPM models typically produce a risk-return relationship that is flatter than the Sharpe-Lintner CAPM's prediction, consistent with the empirical findings.

The thrust of these expanded CAPM models is that beta is insufficient, and that other systematic risk factors affect security returns. The effects of relaxing the assumptions and introducing other independent variables should be quantified and used in estimating the cost of equity capital. The impact of the supplementary variables can be expressed as an additive element to the standard CAPM equation. Letting "a" stand for these other effects, the CAPM equation can be generalized as follows:

$$K = R_F + a + BETA\ (R_M - R_F) \qquad (3)$$

To capture the variables' impact on the slope of the relationship, a coefficient 'b' is substituted for the market risk premium. The generalized CAPM equation becomes:

$$K = R_F + a + b \times BETA \qquad (4)$$

The constants 'a' and 'b' capture market-wide effects which influence security returns, and which must be estimated by statistical techniques.

Empirical studies in finance have demonstrated that several factors besides beta influence security returns: Major factors include the hedging properties of assets against unforeseen changes in opportunities, constraints on investor borrowing, dividend yield as a proxy for tax effects, and size.

II. (3) ZERO-BETA VERSION OF THE CAPM

One of numerous versions of the CAPM developed by researchers which gives rise to a specific formulation of Equation (4) is the so-called zero-beta, or two-factor, CAPM. This version of the CAPM accounts for the effect of margin constraints on investor borrowing and for the existence of investment assets other than publicly-traded common stocks in a market where borrowing and lending rates are divergent. The model has the following form:

$$K = R_Z + BETA\,(R_M - R_Z) \qquad (5)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by several researchers who found a flatter than predicted CAPM consistent with other researchers' findings. In view of the strong empirical support for the zero-beta version of the CAPM, the appellation Empirical CAPM is often attributed to this model.

Although the zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct, attempts to estimate the model are formally equivalent to empirically estimating the coefficients 'a' and 'b' in Equation 4.

II. (4) APPROXIMATIONS TO THE EMPIRICAL CAPM

Approximations to the empirical CAPM have been proposed by assuming that the risk premium on a zero-beta asset is equal to the some fraction of the risk-free rate.

The results of the empirical tests reported below suggest that the following equation provides a workable approximation to the cost of equity capital:

$$K = R_F + 0.3\,(R_M - R_F) + 0.7\ \text{BETA}\,(R_M - R_F) \qquad (6)$$

This approximation rests on the results of an empirical study described in the next section, which statistically relates historical realized returns on a large sample of common stocks to their historical betas. Based on a careful econometric study relating historical portfolio returns to their corresponding historical betas over a long historical period commencing in 1966, the approximation contained in Equation #6 fitted the observed return-risk relationship accurately, is consistent with the results of well-known empirical studies of the CAPM.

Comparing the cost of capital estimate from the standard CAPM of Equation (1) with the estimate from the above empirical approximation, the bias from using the Sharpe-Lintner CAPM can be quantified by subtracting Equation (1) from (6):

$$\text{BIAS} = 0.3\,(R_M - R_F)(1 - \text{BETA}) \qquad (7)$$

The bias is thus positive for a public utility with a beta less than 1. For example, with a market return of 15%, a risk-free rate of 9%, and a beta of 0.80, the cost of equity estimate from the Sharpe-Lintner CAPM is underestimated by 36 basis points (0.36%).

II. (S) MULTIPLE-FACTOR CAPM APPROACH

An asset's hedging properties, tax status, and size are also important determinants of return. The empirical evidence on an asset's degree of protection against unforeseen changes in opportunities is discussed in Morin (1987), op. cit. The empirical evidence on the influence of dividend yields on investors' return requirements is surveyed in Brealey & Myers, Principles of Corporate Finance, McGraw Hill (1988), p. 372. One plausible reason for the dividend yield effect stems from the heavier taxation on dividend income relative to capital gains, which are not taxed until realized. This causes investors to require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks with those of low-yielding stocks.

This effect may have been palliated by recent changes in tax laws. Empirical studies have also found that returns are also affected by size, over and above the effect of beta. For example, the Ibbotson Associates, op. cit., 1987 historical return studies demonstrate that small firms have outperformed large capitalization stocks by about [illegible]

and Carleton, Corporate Finance Concepts and Applications, Kent, 1985, p. 339

III. CAPM EMPIRICAL TEST: DATA, METHODOLOGY, RESULTS

To obtain CAPM estimates of equity costs, I examined the statistical relationship between averaged historical market return and beta for a large sample of securities, using multiple regression techniques. The influence of dividend yield as proxy for tax effects on return was also examined.

III. (1) DATA AND VARIABLES

Data requirements include stock returns, market returns, risk-free interest rates and dividend yield data. The return and dividend yield data are extracted from the CRISP (Center for Research in Security Prices) tapes for the period 1/1960 - 12/1984. Only companies for which consecutive data for at least 60 months prior to the first month of each year and which were available in the Compustat tape were eligible to be in the sample for any given year.

For each company, return is measured as the change in total value over a given month, including dividends and capital gains. Dividend yield is the ratio of cash dividends paid in a given month and the month-end stock price. Monthly returns and dividend yields are summed across months to produce annual returns and dividend yields.

The market return in any given year is computed as the equally weighted average return of all securities listed on the NYSE in that year. The yearly betas for all securities in the sample with at least 60 consecutive months of data prior to that year are estimated from the traditional market model:

$$R_{i,t} - R_{f,t} = a + b_i(R_{M,t} - R_{f,t}) + e_{i,t} \qquad (8)$$

where $R_{i,t}$ = realized return on security 'i' in month t

$R_{M,t}$ = realized return on the market index in month t

$R_{f,t}$ = risk-free rate in month 't'

$e_{i,t}$ = error term with zero mean and finite variance

III. (2) STATISTICAL METHODOLOGY

Securities are first grouped into portfolios based on beta, and dividend yield. The returns, betas, and dividend yields of the portfolios are then computed. The reasons for grouping securities into portfolios are: 1) to improve the statistical efficiency of the empirical test, given that the variance on a portfolio's return is far less than that of an individual security, 2) to attenuate measurement errors through diversification, 3) to produce unbiased estimates of return, beta, and dividend yield for a portfolio by giving equal weight to each security, and 4) to maximize the dispersion of beta, and dividend yield so as to facilitate detection of their relative effects.

The specifics of the methodology are as follows. For each year, Equation #8 is estimated for individual firms, using monthly returns over the previous 5 years. The dividend yield of the security is obtained as of the last year of the 5-year estimation period. Based on the ranked values of beta and dividend yield, the firms in the sample are cross-classified into 35 portfolios, 27 of which are made up of industrials and the remaining 8 of regulated companies. The securities are first ranked according to their estimated beta from minimum to maximum, and divided into beta groups. The securities in each beta group are ranked according to their estimated dividend yields from minimum to maximum, and divided further into sub-groups. Thirty-five portfolios of firms are thus obtained. This procedure is repeated each year based on the most recent beta and dividend yield. To produce efficient statistical estimators and to minimize the variance of portfolio return, portfolios are constructed with an equal number of securities each year. The return, beta and dividend yield of each portfolio are computed by averaging individual security values.

III. 3. EMPIRICAL RESULTS

Exhibits RAMAPP-1 and RAMAPP-2 presents various summary statistics regarding the 35 portfolios, including regression statistics on the market model (Equation #8), average yields, and returns. The estimated value of the intercept 'a' and its 't' statistic appear in columns 2 and 3 for each portfolio. The betas and their corresponding 't' statistic appear in columns 4 and 5. The coefficients of determination (R^2) are in column 6. Both the intercept, 'a', and the slope statistic ('b' or beta) are estimated by regressing the monthly excess return of the equally weighted market portfolio on the corresponding monthly excess return of the equally weighted market portfolio. The average dividend yield, 'd', shown in column 7 is computed by summing the annual yield of each portfolio and averaging over the entire period. The average returns on each portfolio are in column 8.

The portfolio data for industrials and regulated firms are pooled in Exhibit RAMAPP-3, yielding 35 portfolios. The returns, betas, and dividend yields are shown in the various columns for each portfolio. To test for the impact of beta on returns, cross-sectional regression is employed, using the column data of Exhibit RAMAPP-3. The following regression is run:

$$\text{RETURN} = a_0 + a_1\text{BETA}$$

The results are reported on the left-hand side of Exhibit RAMAPP-4, and shown graphically on Figure 2. The fitted relationship between return and beta is given by:

$$\text{RETURN} = .0829 + .0520\ \text{BETA} \qquad (10)$$

$$(t=4.12) \quad (t=4.06)$$

The R^2 of the regression is 0.33. Beta exerts a positive and significant influence on return. Were the traditional Sharpe-Lintner CAPM correct, the intercept in the above relationship should equal the average risk-free rate during the 1966-1984 period, which was about .06, and the slope coefficient should equal (R_M - R_f) or about .06 also. The actual results, however, point to a flatter relationship than predicted by the pure CAPM, as evidenced

finding is consistent with expanded versions of the CAPM, including the empirical approximation of Equation #4 are shown. The approximation almost coincides closely with the observed relationship.

To estimate an asset's cost of equity with the empirical approximation of the CAPM, the current input data for the asset is substituted in the above equation. For example, using a beta of 0.80 a risk-free rate of 9.1% which is the yield on long-term Treasury bonds as of November 1988, a market return of 14.7%, which is the DCF summation of the dividend yield of 3.2% on the Value Line stock index and the consensus expected long-term growth of 11.5% on Zacks' stock universe, the return predicted by the above equation is 13.92%,

$$K = .095 + 0.3\ (.074) + 0.7\ (.074)(0.80) = .1586 \qquad (13)$$

To test for the joint impact of beta and dividend yield on returns, cross-sectional regression is again employed, using the column data of Exhibit RAMAPPB-4. The following regression is estimated:

$$RETURN = a_0 + a_1 BETA + a_2 DIV.\ YLD. \qquad (14)$$

The results are reported on the right-hand side of Exhibit RAMAPPB-4. The fitted relationship is given by:

Both beta and dividend yield exert a positive influence on return, although the influence of dividend yield is marginal. This finding is also consistent with the post-tax version of the CAPM. The positive impact of dividend yield on return is likely to have decreased slightly since the tax reform act of 1986, which has diminished, although not eliminated, the tax advantage of capital gains relative to dividend income.

Arizona Corporation Commission
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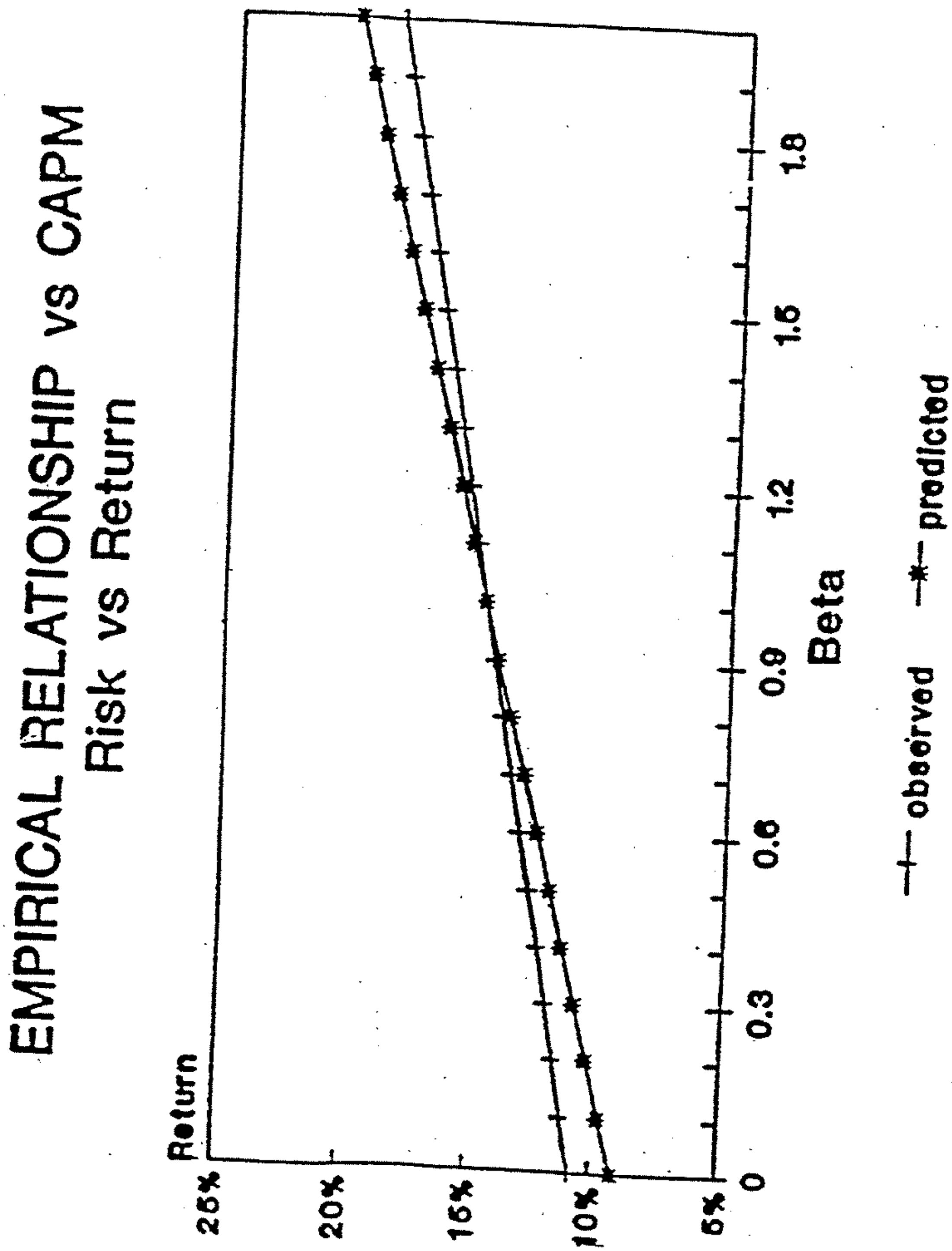
Figure 1.



Arizona Corporation Commission
U S West Communications – Appendix B
Rebuttal Testimony of Dr. Roger A. Morin
Figure 3

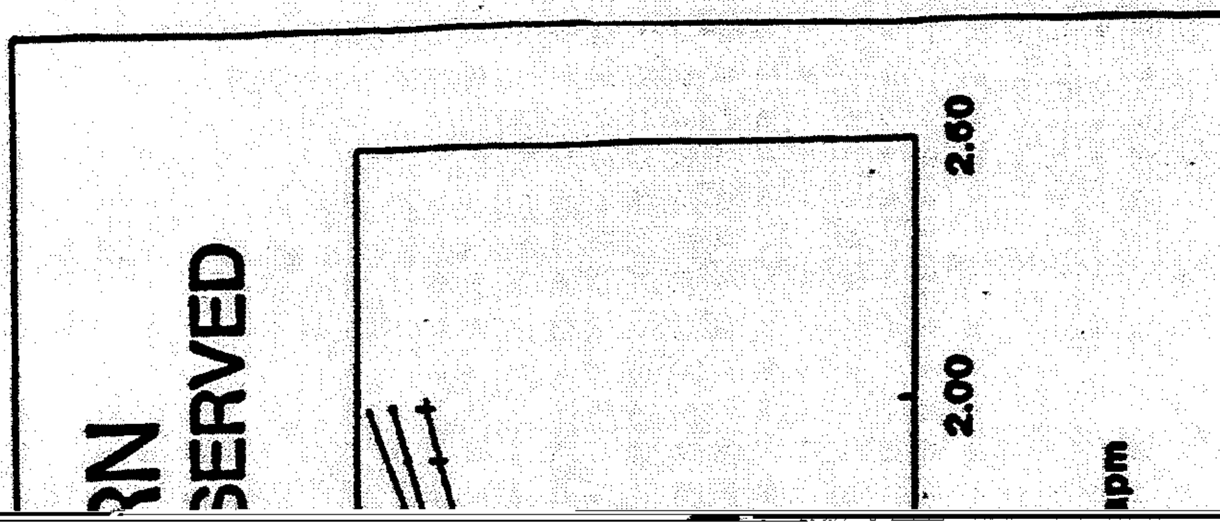


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Exhibit RAMAPP-1

STATISTICS: 27 UNREGULATED PORTFOLIOS 1966-84

PORTFOLIO (1)	a (2)	t(a) (3)	b (4)	t(b) (5)	R-SQUARED (6)	DIV YLD (7)	RETURN (8)
1	0.0010	0.43	0.65	17.32	0.57	0.021	12.[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.65	0.021	10.[illegible]

EXHIBIT RAMAPP- 2

STATISTICS: 8 REGULATED CO PORTFOLIOS 1966-84

PORTFOLIO (1)	a (2)	t(a) (3)	b (4)	t(b) (5)	R-SQUARED (6)	DIV YLD (7)	RETURN (8)
1	0.0002	0.12	0.48	14.21	0.47	0.068	10.50
2	-0.0015	-0.73	0.49	14.06	0.47	0.069	8.50
3	0.0002	0.09	0.46	12.27	0.40	0.084	10.30
4	-0.0014	-0.63	0.50	13.36	0.44	0.085	8.70
5	-0.0013	-0.57	0.56	13.95	0.46	0.057	9.10
6	-0.0013	-0.55	0.59	14.59	0.49	0.056	9.40
7	0.0002	0.08	0.47	12.54	0.41	0.082	10.30
8	-0.0010	-0.43	0.52	13.37	0.44	0.083	9.30

EXHIBIT RAMAPP- 3

POOLED PORTFOLIO DATA

RETURN, BETA, AND DIVIDEND YIELD

Portfolio	Return	Beta	Dividend Yield
1	10.50%	0.48	6.80%
2	8.50%	0.49	6.90%
3	10.30%	0.46	8.40%
4	8.70%	0.50	8.50%
5	9.10%	0.56	5.70%
6	9.40%	0.59	5.60%
7	10.30%	0.47	8.20%
8	9.30%	0.52	8.30%
9	12.50%	0.65	2.10%
10	10.30%	0.73	2.10%
11	13.10%	0.84	2.10%
12	12.70%	0.70	4.20%
13	13.40%	0.72	4.20%
14	11.20%	0.86	4.20%
15	14.60%	0.69	4.20%
16	15.70%	0.77	6.40%
17	14.60%	0.73	6.20%
18	13.40%	0.94	6.50%
19	12.80%	0.99	1.80%
20	13.60%	1.05	1.90%
21	14.90%	0.90	1.40%
22	11.40%	0.93	4.00%
23	13.70%	0.99	4.10%
24	17.00%	0.86	4.00%
25	13.80%	0.88	6.00%
26	14.90%	0.94	6.00%
27	[illegible]	[illegible]	6.10%

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EXHIBIT RAMAPP- 4

REGRESSION RESULTS: RETURN, BETA, DIVIDEND YIELD

RETURN & BETA

Regression Output:

Constant	0.082915
Std Err of Y Est	0.020661
R Squared	0.334653
No. of Observations	[illegible]

RETURN & BETA & DIVIDEND YIELD

Regression Output:

Constant	0.042293
Std Err of Y Est	0.020012
R Squared	0.394712

DOD/HECO-IR-3-28

[Morin Direct, HECO-2001, pp. 1-4]

a. Please list the companies that have bond ratings below investment grade.

b. If the companies included in HECO-2001 that have bond ratings below investment grade were excluded, would the resulting average beta be higher or lower? Please provide support for your response.

Dr. Morin's Response:

None of the companies on Pages 1 through 4 has a bond rating below investment grade, according to the March 2005 edition of AUS Utility Reports. Of the 65 electric utilities shown on HECO-2001 Pages 2-3, only 4 have bond ratings below investment grade: Allegheny Energy, Aquila, Northwestern Corp, and Sierra Pacific Resources. The betas shown on Pages 1 and 4 remain unchanged, while the average beta of the 61 remaining investment-grade companies on Pages 2-3 is 0.74 if these four companies are eliminated from the average.

DOD/HECO-IR-3-29

[Morin Direct, pp. 29, 20]

Please provide an electronic copy (with formulas included) of HECO-2002 and HECO-2003 on a diskette in Microsoft Excel format.

Dr. Morin's Response:

The Excel files "HECO-2002 Elect Hist RP.xls" and "HECO-2003 Nat Gas Hist RP.xls" will be provided under separate transmittal.

DOD/HECO-IR-3-30

[Morin Direct, p. 32]

Please provide an electronic copy of the spreadsheet (with formulas intact) used to create the chart on page 32.

Dr. Morin's Response:

With reference to the Allowed ROE Risk Premium Analysis of Dr. Morin's testimony, the annual allowed ROE data was taken from Regulatory Research Associates, Inc.'s ("*Regulatory Focus*", Major Rate Case Decisions – 1998 - 2004, March 2004) comprehensive survey of ROE decisions by regulators over the period 1987-2004 for electric utilities. The proprietary data cannot be disseminated electronically due to copyright restrictions. The underlying data necessary for the analysis along with the statistical regression are shown below:

Number of Decisions	Year	Allowed ROE	Bond Yield	Risk Premium
33	1995	11.6	6.9	4.7
22	1996	11.4	6.7	4.7
11	1997	11.4	6.6	4.8
10	1998	11.7	5.6	6.1
20	1999	10.8	5.9	4.9
12	2000	11.4	5.9	5.5
18	2001	11.1	5.5	5.6
22	2002	11.2	5.4	5.7
22	2003	11.0	5.0	6.0
3	2004	11.0	5.0	6.0

1995-2004 Regression Output

Constant		9.8714
Std Err of Y Est		0.2515
R Squared		0.83
No. of Observations		10
Degrees of Freedom		8
X Coefficient(s)	-0.7656	
Std Err of Coef.	0.1227	
t-value	-6.2	

DOD/HECO-IR-3-31

[Morin Direct, p. 37, ll. 13-16]

Please provide support from current investor advisory services (or any other source) that predict electric utilities will continue to lower dividend payout over the next several years.

Dr. Morin's Response:

The following table shows the Value Line [illegible]

DOD/HECO-IR-3-32

[Morin Direct, p. 44, ll. 10,11]

Please list the reasons why Dr. Morin believes gas distributors provide a "conservative proxy" for the Company's electric utility operations.

Dr. Morin's Response:

The natural gas distribution industry provides a conservative proxy for the vertically integrated electric utility industry, since gas distribution is quite similar to the electric utility industry's energy delivery business, yet lacks the added risk associated with its generation function.

DOD/HECO-IR-3-33

[Morin Direct, p. 45]

When a bond is sold for a price greater than face value and the difference between the selling price and face value is greater than the issuance costs associated with that bond issuance, is the embedded cost of debt lower or higher than the coupon rate? Why?

<u>Dr. Morin's Response:</u>

Although Dr. Morin did not provide any testimony on HECO's cost of debt, he offers the following comment. When a bond is sold at a premium over face value and flotation cost, the market yield of debt is lower than the coupon rate. Conversely, when a bond is sold at a discount below face value and flotation cost, the market yield of debt is higher than the coupon rate.

DOD/HECO-IR-3-34

[Morin Direct, p. 47, ll. 13]

What is the annual rate impact on HECO's customers of a 30 basis point increase in the return on common equity? Please provide supporting calculations.

Dr. Morin's Response:

See Company response.

HECO Response:

The estimated impact of a 30 basis point increase in the return on common equity (from 11.5% to 11.8%) on revenue requirements is approximately $3 million. The estimated 2005 test year composite cost of capital with an 11.80% return on common equity (replacing the 11.5% in HECO-2101 filed on 11/12/04 and with no other revisions) is 9.27%. With 9.27% as the rate of return on rate base, the increase in revenues over revenues at current effective rates is 10.2% (versus the 9.9% increase reflected in HECO's November 12, 2005 direct testimony filing.)

DOD/HECO-IR-3-35

[Morin Direct, p. 60, l. 5]

Please provide a complete copy of the article cited.

Dr. Morin's Response:

Enclosed.

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Reprinted from RatingsDirect

Credit Implications of Public Power Utilities' Power Purchases

Credit Analyst: David Bodek, New York (1) 212-438-7969

We are often asked whether Standard & Poor's Ratings Services' credit ratings differentiate between those public power utilities that directly fund and build generation and those utilities that meet capacity needs through market purchases and contractual arrangements. In light of the high level of interest in our thoughts on the topic of "buy versus build," this article provides an overview of the credit quality issues surrounding the procurement of energy resources needed to meet load.

Buy or Build?

Load growth typically does not occur in increments that correspond to the threshold levels of capacity additions that economically justify the construction of power plants. As a result, public power utilities have a long history of purchasing a portion of their power needs until they reach a level of load growth that enables them to realize the economies of scale needed to justify capacity additions.

Purchases by public power utilities include spot-market purchases, purchases under contracts, and participation in joint-action agencies. Joint-action agencies allow public power utilities to achieve economies of scale by banding together with others whose needs, on a stand-alone basis, also do not reach the threshold for capacity additions.

Standard & Poor's recognizes that there can be many operational benefits associated with purchasing power versus developing resources. For example, purchasing from a joint action agency or even from a for-profit generation company may translate into greater operational and price stability than may be realized by building a generation asset. However, the operational considerations associated with buy versus build must be explored against the backdrop of the financial analysis of buy versus build.

It is clear that the financial metrics of a utility that issues debt to build a power plant must include the debt issued [illegible] agreement (PPA) assumes a financial obligation. This financial obligation is usually expressed as a capacity payment. Importantly, the obligation to make a capacity payment does not look or feel much different than debt service. It just happens to be the recovery of someone else's capital investment that the public power utility is called upon to fund.

Even if the electricity price under the PPA is not expressed as having both a capacity and an energy component, we view the power price as including an implied capacity component that represents the energy supplier's recovery of its capital investment.

Some argue that a PPA should not translate into a debt-like obligation and should not affect financial ratios. In response, consider whether a utility that has committed to pay a capacity charge obligation to a power producer should be viewed as exhibiting stronger credit quality than a utility that has committed to pay its proportionate share of a joint action agency's debt service. The answer is no, the utility that purchases power from merchant energy companies should not be viewed as more creditworthy than a utility whose financial metrics are adjusted to reflect participation in a joint-action agency. To conclude otherwise would lead to incongruous results. A utility that has purchased all of its power under contracts and whose balance sheet only reflects distribution debt should not be deemed to be stronger than a utility that has built generation or that participates in a joint-action agency. In the final analysis, each of these vertically integrated utilities has incurred fixed obligations related to its load-serving commitments. Moreover, the utility that contracts with a for-profit generation company may be at a disadvantage because it ultimately has to pay a portion of the generation company's higher cost of capital and taxes.

Prepayment of Electricity Purchases

Recently, the IRS issued regulations that permit public power utilities to issue tax-exempt debt to prepay electricity purchases. These regulations add a new facet to the buy-versus-build debate.

Prepay transactions are attractive for many reasons. Some of the benefits include:

- The ability of tax-exempt debt issuers to leverage their favorable capital costs into an advantageous power supply agreement with a taxable entity; and
- The purchase of energy from a diverse portfolio of generation assets may provide cost and operational advantages that cannot be realized by self-building a single generation asset.

Standard & Poor's recognizes that some prepayment transactions may give rise to opportunities for savings and operational and price stability. At the same time, it must be recognized that the prepayment of electric purchases is not meaningfully different than entering into a PPA with an obligation to make capacity payments. The principal distinction is that under a PPA, capacity payments are made contemporaneously with the use of the capacity. In a prepayment transaction, capacity is paid for well in advance of its use. Just the same, the repayment of the debt issued to make the prepayment is amortized on a schedule designed to mirror the anticipated use of the capacity and energy, which demonstrates the similarities between a prepayment transaction and a PPA.

The financial metrics of a utility that reserves a portion of another utility's capacity through a prepayment need to be adjusted to reflect the prepayment debt obligation that has been incurred. The bottom line is that, a utility that prepays has in effect purchased a portion of another utility's generation portfolio for a period of time and has incurred a fixed obligation in connection with that purchase. Any savings that may be realized by participation in a prepayment transaction mitigate the burdens created by the debt obligation but do not negate the fixed obligation.

It is important to emphasize another consideration in examining the credit quality implications of prepayment transactions and, for that matter, all power procurement. Standard & Poor's ratings have never relied solely on quantitative measures. Rather, our analysis of electric utilities' credit quality focuses heavily on qualitative factors that define the strength of the financial performance that a utility must demonstrate to support a given rating. Our quantitative analysis for all utilities is predicated on the qualitative analysis of six principal areas:

- The utility's operational profile;
- An examination of the markets served by the utility;
- The utility's competitive posture;
- An examination of regulatory issues including ratemaking flexibility and policies that govern the amount of general fund transfers;
- The strengths that the management team brings to the table; and
- The strength of the bondholder protections provided by the bond indenture.

The evaluation of a prepayment transaction, will consider additional factors. They include:

- The economics of the energy that is being prepaid;
- The financial capacity of the prepaying utility to support the fixed commitments;
- The operational risks that are avoided or created by outsourcing the operation of power production to a third party;
- Where appropriate, pricing benefits associated with obtaining a system rate for power, as compared with self-build pricing that might hinge on the efficiency and dispatch of a single asset; and, the final and most important consideration,
- Does the prepayment transaction merely substitute one fixed obligation that has already been factored into the credit rating with another fixed obligation, or does it create a new fixed obligation that has yet to be factored into the rating?

Based on the analysis of the amalgam of these factors, Standard & Poor's will assess the quantitative implications of debt associated with the prepayment of electricity supply or any other purchases of electricity from third parties. The extent of the rating implications, if any, will be resolved case by case with reference to the qualitative and quantitative considerations cited.

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DOD/HECO-IR-3-36

[Morin Direct, p. 62, l. 15]

a. Is the electric industry average debt ratio of 52% cited by Dr. Morin adjusted for purchased power debt-equivalents?

b. Dr. Morin makes his financial risk comparisons based on HECO's 2003 year-end capitalization. How does the Company's 2003 year-end capital structure compare to the capital structure it requests in this proceeding?

Dr. Morin's Response:

a. No.

b. See Company response.

HECO Response:

b. For the end of year 2003 book capital structure for HECO (Oahu) see the response to DOD/HECO-IR-3-1 which was filed with the Department of Defense and the Consumer Advocate on April 19, 2005. The proposed test year 2005 rate case capitalization appears on Attachment 5 to HECO's transmittal of updates provided on May 5, 2005. Note that during 2004 the amount of hybrids in the capital structure of HECO was reduced by $30 million.

DOD/HECO-IR-3-37

[Morin Direct, Appendix A, HECO-2011]

a. Please provide a complete copy of the 2000 study referenced on page 5.

b. Please provide a complete copy of the May 2002 study referenced on page 6.

c. Please provide a complete copy of the spreadsheet from which the graph on page 7 was created.

d. Were either of the studies referenced published in any scholarly journal, or peer reviewed?

e. Please explain why the tenth portfolio was not included in the graph on page 7. How would the results differ if it had been?

Dr. Morin's Response:

a. The 2000 study is superseded by the 2002 study.

b. & c. The data is attached in hard copy form. Value Line does not allow the dissemination of its proprietary data in electronic format for obvious copyright reasons.

d. The analysis was subjected to peer review when the book itself was subjected to an extensive review process from several reviewers by the publisher, as will the upcoming 2005 edition. Subsequent to the publication of the book, the study was certainly subjected to frequent scrutiny by the regulatory process in numerous rate cases.

e. The tenth portfolio contained several small cap stocks and was excluded from the relationship due to significant size effects that obscure the relationship between return and beta. Dr. Morin did not investigate the impact of size on the CAPM.

	Company Name	Beta	Return 10-Yr
1	Golden Star Res	-0.10	10.69
2	U.S. Energy Corp.	0.15	1.48
3	Versar Inc.	0.15	8.10
4	National Home Health	0.15	11.66
5	Novitron Intl Inc	0.20	0.45
6	Glamis Gold Ltd	0.20	9.30
7	Bovar Inc.	0.20	1.44
8	Agnico-Eagle Mines	0.20	14.72
9	Wellco Enterprises Inc.	0.25	16.82
10	ACMAT Corp	0.25	4.36
11	British Amer Tobacco ADR	0.25	20.16
12	Elmer's Restaurants Inc	0.30	13.66
13	ASA Ltd.	0.30	1.50
14	Barnwell Industries	0.30	2.87
15	B & H Ocean Carriers	0.30	3.02
16	Gen'l Binding	0.30	1.20
17	FIRST REGIONAL BANCORP	0.30	14.47
18	Banyan Strategic Rlty Tr	0.30	8.65
19	Coca-Cola Bottling	0.30	12.67
20	Newmont Mining	0.30	0.35
21	Maxco Inc.	0.30	5.38
22	Gallery Of History Inc.	0.30	10.06
23	Greenbriar Corp	0.30	14.06
24	American First Apt Inv L P	0.30	14.13
25	Sunlink Health Sys	0.30	6.62
26	Independence Hldg. Co	0.30	18.49
27	Educational Development	0.30	26.63
28	Control Chief Hldgs	0.35	11.22
29	Corby Distilleries Ltd.	0.35	11.95
30	VSE Corp.	0.35	11.95
31	INTL ELECTRONICS	0.35	1.31
32	E-Z-EM Inc.	0.35	6.03
33	Panhandle Royalty 'A'	0.35	19.62
34	Abrams Ind	0.35	4.85
35	Howell Corp.	0.35	7.43
36	Great Northern Iron Ore	0.35	8.75
37	Clean Harbors	0.35	1.72
38	Leon's Furniture Ltd.	0.35	13.95
39	Weyco Group	0.35	14.10
40	Raytech Corp.	0.35	6.50
41	HMG Courtland Prop	0.35	6.35
42	Parkland Industries Ltd.	0.35	15.13
43	Meridian Gold Inc	0.35	13.97
44	Bancinsurance Corp	0.40	11.80
45	UNITIL Corp.	0.40	11.38
46	First Of Long Island	0.40	16.57
47	Int'l Aluminum	0.40	3.45
48	Wall Financial Corp.	0.40	5.87
49	Air T Inc	0.40	10.98

50	Glacier Water Svcs.	0.40	1.11
51	USA Truck	0.40	4.90
52	Federal Screw Works	0.40	18.99
53	Nuveen Muni Value Fund	0.40	4.78
54	PRESIDENTIAL RLTY 'A'	0.40	16.73
55	TRANSMATION INC	0.40	0.36
56	Chester Valley Bancorp.	0.40	18.55
57	Max & Erma's Restaurants	0.40	15.13
58	COMMUNITY FINL CORP VA	0.40	15.18
59	Foodarama Supermarkets Inc.	0.40	9.87
60	Pizza Inn Inc.	0.40	8.82
61	Hancock (J) Patriot Div	0.40	9.11
62	Energy West Inc.	0.40	10.63
63	MARSH SUPERMARKETS 'A'	0.40	1.96
64	Ziegler Companies Inc.	0.40	1.79
65	Placer Dome	0.40	2.94
66	clark (dick) prods.	0.40	18.19
67	I I C Industries	0.40	6.92
68	Espey Mfg. & Electronics Corp.	0.40	4.76
69	Saucony Inc	0.40	7.89
70	Seneca Foods 'B'	0.40	6.03
71	McRae Ind 'A'	0.40	6.66
72	Natl Beverage	0.40	19.29
73	Hancock (J) Invs. Trust	0.40	6.61
74	Twin Disc Inc.	0.40	1.20
75	Financial Inds Corp.	0.40	4.41
76	PVC Container	0.40	14.01
77	Amer. Physicians Service Gp	0.40	6.80
78	Dover Industries Ltd	0.40	4.21
79	Barrick Gold	0.40	7.06
80	Chesapeake Utilities Corp.	0.40	11.23
81	Royal Gold	0.40	57.25
82	Security Cap Corp	0.40	32.73
83	Western Resources	0.40	2.02
84	Mestek Inc.	0.40	7.96
85	Bank South Carolina	0.40	9.28
86	Bridgford Foods	0.40	0.10
87	Todd Shipyard Cp Del	0.45	10.30
88	Multi-Color Corp	0.45	10.26
89	Hoenig Group Inc.	0.45	8.74
90	Sun BanCorp. Inc.	0.45	21.45
91	South Jersey Inds.	0.45	11.58
92	Raven Inds.	0.45	12.31
93	Permian Basin Rty Tr	0.45	13.48
94	S&K Famous Brands	0.45	4.26
95	ATCO Ltd.	0.45	19.20
96	Aristotle Corp NEW	0.45	5.44
97	Maine Public Service	0.45	8.52
98	SERVOTRONICS INC DEL	0.45	0.61
99	Exco Technologies Ltd.	0.45	17.83
100	United Mobile Homes	0.45	21.76

101	Wolohan Lumber	0.45	3.16
102	Empire Company Ltd.	0.45	18.03
103	Arden Group 'A'	0.45	21.98
104	Mueller (Paul) Co	0.45	4.56
105	McGraw-Hill Ryerson Ltd.	0.45	3.40
106	Mesabi Trust	0.45	19.52
107	EnergySouth Inc	0.45	18.75
108	Daily Journal Corp.-SC	0.45	11.51
109	MOOG INC 'B'	0.45	19.54
110	Northern States Finl	0.45	14.98
111	FIRST UNITED CORP	0.45	10.49
112	COMARCO Inc.	0.45	10.59
113	United Finl Corp Minn	0.45	9.97
114	Sizeler Prop Inv	0.45	8.85
115	Bowl America Cl 'A'	0.45	7.62
116	ACM Income Fund	0.45	7.61
117	Apco Argentina	0.45	4.65
118	Tofutti Brands	0.45	8.92
119	SCANA Corp.	0.45	13.75
120	EMC Insurance	0.45	12.78
121	Marsh Supermarkets 'B'	0.45	1.23
122	Rothmans Inc.	0.45	16.71
123	Harris Steel	0.45	15.38
124	Canam Manac Group	0.45	16.83
125	Merchants Group Inc.	0.45	6.50
126	FPL Group	0.45	11.20
127	Pope Resources L.P.	0.45	6.16
128	Allen Organ Co	0.45	2.91
129	Aerosonic Corp.	0.45	25.28
130	Tasty Baking	0.45	5.83
131	Empire Dist. Elec.	0.45	6.50
132	First Bancorp. NC	0.45	24.21
133	Winpak Ltd.	0.45	24.21
134	Healthcare Svcs.	0.45	8.74
135	Minuteman Intl	0.45	5.95
136	Delta Natural Gas	0.45	11.01
137	Income Oppurtunity Rlty	0.45	24.97
138	Consol. Edison	0.45	10.88
139	NiSource Inc.	0.45	11.05
140	BF Enterprises	0.45	9.65
141	LIFEWAY FOODS	0.45	5.63
142	Maynard Oil Co	0.45	11.79
143	J.W. Mays Inc.	0.45	0.94
144	Metro Inc.	0.45	32.28
145	Conn. Water Services	0.45	17.23
146	Donnelly Corp. 'A'	0.45	5.68
147	Arbor Mem Svcs Inc.	0.45	2.94
148	Middlesex Water	0.45	15.42
149	Emex Corp.	0.45	0.67
150	MFS Multimarket Income	0.45	6.27
151	Ronson Corp.	0.45	7.12

152 Urstadt Biddle Pptys	0.50	7.88		
153 Health Care Property	0.50	14.34		
154 UIL Holdings	0.50	11.96		
155 DQE	0.50	4.66		
156 Covista Communications Inc	0.50	16.17		
157 U S Restaurant Pptys	0.50	15.02		
158 Dorchester Hugoton	0.50	11.86		
159 Pubco Corp.	0.50	8.02		
160 RehabCare Group	0.50	19.45		
161 American Vanguard	0.50	14.42		
162 Ameriana Bancorp	0.50	11.88		
163 TRANSCONTINENTAL RLTY NEW	0.50	19.46		
164 Old Second Bancorp	0.50	16.09		
165 Exponent Inc	0.50	4.47		
166 Hormel Foods	0.50	12.34		
167 Fidelity Bancorp Inc	0.50	14.84		
168 Berkshire Bancorp Inc	0.50	14.47		
169 Flexsteel Inds	0.50	4.43		
170 Access Anytime Bancorp Inc	0.50	19.65		
171 Acktion Corp.	0.50	16.22		
172 Datamark Systems Group Inc	0.50	6.13		
173 Potomac Elec. Power	0.50	6.15		
174 Coors (Adolph) 'B'	0.50	19.55		
175 NorthWestern Corp.	0.50	10.25		
176 Reitmans (Canada) Ltd.	0.50	10.25		
177 Woodhead Industries	0.50	13.13		
178 Tech/Ops Sevcon Inc.	0.50	12.78		
179 RGS Energy Group	0.50	13.05		
180 Hancock Fabrics	0.50	7.63		
181 First Fin'l Corp. IN	0.50	14.15		
182 Glentel Inc.	0.50	5.34		
183 Southwest Water	0.50	18.38		
184 Cen. Vermont Pub. Serv.	0.50	5.27		
185 State Bancorp Inc NY	0.50	16.98		
186 Hollinger Inc.	0.50	5.28		
187 CB Bancshares HI	0.50	11.99		
188 Interstate Bakeries	0.50	15.05		
189 Fortis Inc.	0.50	14.56	0.41	10.87
190 Quipp Inc	0.50	18.07		
191 Franklin Electric	0.50	16.74		
192 Nationwide Health Pptys Inc.	0.50	12.01		
193 FPI Limited	0.50	7.76		
194 MESA LABS	0.50	8.14		
195 Horizon Financial	0.50	10.80		
196 Natl HealthCare L.P.	0.50	7.90		
197 Danielson Holding	0.50	7.50		
198 Castle Energy Corp.	0.50	17.52		
199 ALLETE	0.50	12.61		
200 Buckeye Partners L.P.	0.50	18.68		
201 Pinnacle West Capital	0.50	12.47		
202 BHA Group	0.50	4.96		

203	Aero System Engineer	0.50	11.03
204	Sabine Royalty Trust	0.50	19.19
205	WFI Inds Ltd	0.50	19.11
206	Hershey Foods	0.50	15.05
207	Citizens Inc. 'A'	0.50	5.95
208	Amer. Water Works	0.50	18.93
209	MICROWAVE FILTER	0.50	14.22
210	Community Finl Grp Inc	0.50	18.85
211	Tompkins County Tr	0.50	18.75
212	P&F Industries	0.50	18.82
213	Hawkins Inc	0.50	14.29
214	OGE Energy	0.50	7.87
215	Farmer Bros. Co.	0.50	12.55
216	Landauer Inc.	0.50	14.28
217	Callon Pete Co	0.50	7.88
218	WD-40 Co.	0.50	8.07
219	Noland Company	0.50	7.16
220	Wisconsin Energy	0.50	5.21
221	Koss Corp	0.50	33.27
222	Powell Industries	0.50	10.07
223	ImmuCell Corp.	0.50	9.26
224	Moore Medical Corp.	0.50	2.55
225	Bryn Mawr Bank Corp.	0.50	25.39
226	Andres Wines Ltd. 'A'	0.50	9.05
227	Cont'l Materials Corp	0.50	21.31
228	First Colonial Group	0.50	30.80
229	Pamrapo Bancorp	0.50	21.27
230	Aberdeen Asia-Pac. Fd.	0.50	2.41
231	Glendale Intl Corporation	0.50	9.61
232	Bairnco Corp.	0.50	0.26
233	Hawaiian Elec.	0.50	9.07
234	Anangel-American Shipholdings	0.50	0.66
235	Canada Bread Ltd	0.50	3.81
236	Parkvale Financial Corp.	0.50	22.69
237	Wainwright Bank & Trust Co.	0.50	8.64
238	Schawk Inc.	0.50	3.05
239	Patriot Transportation Holdin	0.50	9.16
240	Ennis Business Forms	0.50	2.99
241	Sonesta Int'l Hotels Corp.	0.50	9.18
242	Great Southern Bancorp	0.50	30.88
243	Laurel Cap Group Inc.	0.50	22.65
244	Chalone Wine Group Ltd.	0.50	1.01
245	DWYER GROUP INC	0.50	2.80
246	Madison Gas & Elec.	0.50	9.82
247	Superior Uniform Group	0.50	0.24
248	Scope Industries	0.50	9.73
249	Action Products Intl	0.50	0.09
250	Courier Corp.	0.50	27.14
251	Warren Bancorp.	0.55	16.28
252	U S Lime & Minerals	0.55	4.20
253	Universal Health Realty	0.55	14.01

254	RGC Resources Inc	0.55	8.48
255	Nobility Homes Inc.	0.55	33.94
256	Penn Engr.& Mfg.	0.55	20.58
257	F.M.S. Financial	0.55	23.35
258	Northeast Utilities	0.55	2.68
259	Puerto Rican Cement	0.55	3.14
260	Lydall Inc.	0.55	3.43
261	Simmons First Nat'l 'A'	0.55	14.83
262	Lance Inc.	0.55	0.68
263	Conectiv	0.55	8.04
264	First Oak Brk Bncshs	0.55	24.60
265	Vulcan Int'l	0.55	12.04
266	America Service Group	0.55	12.13
267	TransCanada Pipe.	0.55	7.51
268	Aceto Corp.	0.55	5.65
269	Credo Pete Corp.	0.55	16.12
270	United Dominion R'lty	0.55	12.78
271	Laclede Group	0.55	8.86
272	FirstEnergy Corp.	0.55	11.80
273	Decorator Inds Inc.	0.55	16.40
274	Knape & Vogt Mfg.	0.55	3.13
275	Cinergy Corp.	0.55	9.89
276	Public Serv. Enterprise	0.55	12.82
277	CorVel Corp.	0.55	20.91
278	TECO Energy	0.55	8.69
279	Span-America Medical Systems	0.55	0.01
280	NSTAR	0.55	13.32
281	New Brunswick Scientific Co	0.55	10.60
282	Bedford Ppty Invs	0.55	23.61
283	SNC Lavalin Group Inc.	0.55	23.64
284	Seacoast Bk. Fla 'A'	0.55	18.39
285	Atlantis Plastics	0.55	3.30
286	National Sec Group Inc	0.55	9.94
287	Lindsey Morden Group Inc.	0.55	3.29
288	Aecon Group Inc	0.55	18.48
289	Uni-Select Inc.	0.55	32.23
290	Amer. Elec. Power	0.55	9.93
291	DTE Energy	0.55	9.19
292	Consol. Tomoka Land	0.55	8.24
293	Kaneb Pipe Line Part	0.55	17.14
294	Advanced Technical Prods. Inc	0.55	17.15
295	First Citzn BncSh-NC	0.55	14.69
296	CCL Industries Inc. 'A'	0.55	10.94
297	Merchants Bancshares Inc.	0.55	16.57
298	Cascade Natural Gas	0.55	9.93
299	Canadian Utilities 'B'	0.55	16.46
300	Alexanders Inc.	0.55	18.66
301	NBT Bancorp	0.55	16.46
302	Alleghany Corp.	0.55	5.83
303	Revenue Properties Co. Ltd.	0.55	4.17
304	Lawson Products	0.55	3.30

305	Chicago Rivet & Mach Co	0.55	14.72
306	Right Management	0.55	32.03
307	First Merchants Corp	0.55	14.65
308	Synovis Life Technologies Inc	0.55	3.84
309	Heinz (H.J.)	0.55	9.14
310	Bio-Reference Labs Inc	0.55	23.66
311	NORTHERN TECH INTL	0.55	8.72
312	Liqui-Box Corp.	0.55	11.33
313	WPS Resources	0.55	10.71
314	Florida Public Utilities	0.55	12.14
315	G't Plains Energy	0.55	6.39
316	PNM Resources	0.55	4.46
317	Lockheed Martin	0.55	17.74
318	Progress Finl Corp	0.55	12.60
319	Flow Int'l	0.55	7.67
320	Arctic Cat Inc	0.55	14.39
321	Gray Comm. Sys.	0.55	16.01
322	J2 COMMUNICAT	0.55	12.47
323	Ameren Corp.	0.55	8.94
324	Village Super Market 'A'	0.55	17.73
325	Pacific Northern Gas Ltd.	0.55	1.65
326	Atmos Energy	0.55	10.27
327	Astral Media Inc. 'A'	0.55	9.04
328	Nevada Chemicals Inc	0.55	8.79
329	Alico Inc.	0.55	4.38
330	SJW Corp.	0.55	15.07
331	ADV Neuromodulation Sys	0.55	17.70
332	United Park City Mns	0.55	5.57
333	Community Banks Pa	0.55	19.79
334	Green Mountain Pwr.	0.55	1.98
335	Chemed Corp.	0.55	8.20
336	Elxsi Corporation	0.55	2.02
337	CSS Industries	0.55	7.95
338	Entergy Corp.	0.55	11.24
339	Sparton Corp.	0.55	1.76
340	Collins Ind.	0.55	0.14
341	Alliant Energy	0.55	4.74
342	Savannah BanCorp. Inc.	0.55	15.72
343	CHUM Ltd.	0.55	10.19
344	Suffolk Bancorp	0.55	28.72
345	McCormick & Co.	0.55	11.16
346	Amer Biltrite Inc.	0.55	6.58
347	Cobra Electronics	0.55	8.21
348	West Fraser Timber Co.	0.55	10.34
349	Frisch's Restaurants	0.55	4.27
350	CMS Energy Corp.	0.55	6.14
351	Puget Energy Inc.	0.55	5.45
352	Valhi Inc.	0.55	8.55
353	BC Gas Inc.	0.55	14.75
354	Church & Dwight	0.55	10.08
355	City Holding	0.55	5.58

356	Waters Instruments	0.55	14.63		
357	Parkway Pptys Inc	0.55	33.92		
358	Benihana Inc	0.55	27.12		
359	Great American Fin'l Resource	0.55	11.90		
360	Texas Pacif. Land Tr	0.55	8.00		
361	Ecology & Environment	0.55	1.63		
362	World Acceptance	0.55	11.49		
363	Enbridge Inc.	0.55	20.36		
364	IDACORP Inc.	0.55	9.67		
365	Finning International Inc.	0.60	17.08		
366	Virco Mfg Co.	0.60	14.75		
367	Cooperative Bankshares	0.60	17.51		
368	Nash Finch Co.	0.60	8.19		
369	First Fed Fin'L - Ky	0.60	17.20		
370	Valmont Inds.	0.60	13.47		
371	UMB Financial Corp.	0.60	8.12		
372	Piedmont Natural Gas	0.60	13.51		
373	Ampco-Pittsburgh	0.60	7.17		
374	Universal Corp.	0.60	8.79		
375	NICOR Inc.	0.60	13.63		
376	Anheuser-Busch	0.60	17.46		
377	Analogic Corp.	0.60	17.21		
378	Energy East Corp.	0.60	9.83	0.54	12.02
379	Loblaw Companies Limited	0.60	27.57		
380	Hancock Holding	0.60	14.99		
381	Natl Penn Bancshares	0.60	16.88		
382	Community Tr Bancorp	0.60	15.70		
383	Scudder High Income	0.60	7.91		
384	Toreador Res Corp.	0.60	6.92		
385	NAPCO Security Systems Inc.	0.60	11.17		
386	National Fuel Gas	0.60	11.17		
387	CPB Inc.	0.60	15.37		
388	San Juan Basin Rlty.	0.60	15.73		
389	PG&E Corp.	0.60	1.42		
390	National Health Invs Inc.	0.60	6.14		
391	Massbank Corp.	0.60	15.57		
392	Newhall Land & Farming	0.60	8.72		
393	New Jersey Resources	0.60	14.83		
394	HRPT Pptys Tr	0.60	6.77		
395	Reliant Energy	0.60	7.97		
396	Atalanta/Sosnoff Capital Corp	0.60	11.42		
397	AGL Resources	0.60	9.43		
398	Arrow Financial	0.60	26.68		
399	Commercial Net Lease	0.60	14.41		
400	MDU Resources	0.60	15.09		
401	Penn. R.E.I.T.	0.60	11.30		
402	ML Macadamia Orchards LP	0.60	2.00		
403	ITO YOKADO LTD	0.60	6.11		
404	Prime Medical Services	0.60	25.06		
405	Flag Finl Corp	0.60	16.04		
406	GOLDFIELD CORP	0.60	2.92		

407	Health Care REIT	0.60	13.76
408	Met-Pro Corp.	0.60	11.68
409	Second Bancorp Inc	0.60	16.49
410	Gorman-Rupp Co.	0.60	9.21
411	Domco Tarkett Inc	0.60	2.92
412	West Pharmac. Svcs.	0.60	5.92
413	Steak n Shake	0.60	16.75
414	Shell Canada	0.60	16.81
415	Redwood Empire Bancorp.	0.60	16.82
416	Novo Nordisk ADR	0.60	13.90
417	Hilb Rogal&Hamilton	0.60	24.16
418	BOK Financial	0.60	25.02
419	Cadbury Schweppes	0.60	11.02
420	Molson Inc. Ltd. 'A'	0.60	11.06
421	Indep Bank Corp/MI	0.60	24.72
422	CRAWFORD & CO 'A'	0.60	1.20
423	Imperial Oil Ltd.	0.60	16.31
424	Toromont Industries Ltd.	0.60	31.22
425	Marten Transport Ltd.	0.60	11.32
426	New England Bus.	0.60	9.80
427	Park National	0.60	16.35
428	Sensient Techn.	0.60	7.32
429	Washington R.E.I.T.	0.60	12.28
430	CH Energy Group	0.60	13.08
431	Baldwin & Lyons	0.60	12.64
432	Schulman (A.)	0.60	0.65
433	Brandywine Realty Trust	0.60	34.74
434	Harleysville Nat'l	0.60	9.96
435	Slater STL Inc	0.60	18.47
436	Newmil Bancorp Inc.	0.60	21.21
437	Weingarten Realty	0.60	12.54
438	TransAlta Corp.	0.60	12.54
439	Weis Markets	0.60	3.72
440	Kellogg	0.60	4.86
441	PS Business Parks	0.60	18.18
442	Eastern Company	0.60	9.11
443	Aquila Inc.	0.60	4.38
444	WGL Holdings Inc.	0.60	10.13
445	Avista Corp.	0.60	5.19
446	CAPITOL BANCORP MICH	0.60	18.85
447	Petrol Helicopters	0.60	8.79
448	TXU Corp.	0.60	10.29
449	Nelson (Thomas) Inc.	0.60	3.39
450	Psychemedics Corp.	0.60	3.38
451	Sara Lee Corp.	0.60	8.38
452	St. Lawrence Cement	0.60	9.98
453	TCW Conv. Sec. Fund	0.60	12.61
454	Utah Medical Prods.	0.60	5.00
455	Aber Diamond Corporation	0.60	35.22
456	MITEK SYST INC	0.60	12.55
457	Duke Energy	0.60	12.92

458	Capital Pac Hldgs	0.60	8.37
459	Del Labs	0.60	19.50
460	Lufkin Inds.	0.60	4.44
461	Otter Tail Corp.	0.60	13.03
462	Gen'l Mills	0.60	8.48
463	Cleco Corp.	0.60	12.99
464	Black Hills	0.60	10.65
465	Rentrak Corp	0.60	0.50
466	Chemical Financial	0.60	13.37
467	Ark Restaurants Corp.	0.60	5.46
468	Investors Title Co	0.60	20.30
469	Allegheny Energy	0.60	13.30
470	Ventas Inc	0.60	4.25
471	Westerbeke Corp	0.60	3.56
472	Drew Industries	0.60	22.70
473	Bank Of Granite	0.60	12.24
474	Daxor Corp.	0.60	21.61
475	Dupont Canada Inc.	0.60	20.63
476	Velcro Inds. N V	0.60	17.88
477	AAON Inc.	0.60	46.86
478	Central Bancorp Inc Mass	0.60	20.62
479	Owens & Minor	0.60	12.31
480	IRT Property Co	0.60	11.87
481	BERGER HLDGS LTD.	0.60	37.08
482	Ingles Markets 'A'	0.60	12.70
483	Phila. Suburban	0.60	20.98
484	Pacific Northwest Bancorp	0.60	17.71
485	United Capital Corp.	0.60	20.94
486	Bancorp Conn Inc	0.60	33.39
487	TransTechnology	0.65	2.34
488	TEPPCO Partners L.P.	0.65	21.26
489	Int'l Multifoods	0.65	4.49
490	First Finl Bancorp	0.65	14.12
491	ICU Medical	0.65	26.02
492	Century BanCorp.	0.65	29.55
493	Patrick Inds Inc.	0.65	15.49
494	Synthetech Inc.	0.65	4.67
495	Double Eagle Pet & Min	0.65	19.50
496	Procter & Gamble	0.65	15.69
497	Community Bank Sys.	0.65	19.43
498	Interchange Fin'l Services	0.65	21.52
499	Ahold ADR	0.65	7.53
500	Flamemaster Corp	0.65	3.62
501	National TechTeam	0.65	11.52
502	LESCO Inc.	0.65	0.59
503	Olin Corp.	0.65	0.43
504	Monro Muffler Brake	0.65	8.58
505	Amer. Locker Group	0.65	25.36
506	White Mtns Ins Group Ltd	0.65	21.54
507	Steel Technologies	0.65	1.30
508	Ins. Auto Auctions	0.65	1.59

509	New Hampshire Thrift	0.65	17.56
510	Stepan Company	0.65	6.88
511	MAAX Inc.	0.65	28.09
512	Hector Communications	0.65	6.58
513	Tecumseh Products	0.65	6.56
514	Airlease Ltd.	0.65	8.93
515	DPL Inc.	0.65	14.53
516	LSB Bancshares	0.65	12.44
517	Brown-Forman 'B'	0.65	14.59
518	Kinder Morgan	0.65	20.12
519	TransMontaigne Inc	0.65	27.06
520	Mocon Inc.	0.65	4.25
521	Albertson's Inc.	0.65	6.78
522	Allied Research Corp.	0.65	9.45
523	Weston (George)	0.65	27.62
524	Engineered Support Sys	0.65	49.30
525	Embrex Inc.	0.65	14.86
526	Equitable Resources	0.65	14.85
527	Baker (Michael) Corp.	0.65	1.77
528	Public Storage	0.65	20.89
529	Andersen Group Inc.	0.65	3.91
530	Omega Fin'l	0.65	12.48
531	Meridian Med Tech	0.65	6.53
532	Q-Med Inc	0.65	15.05
533	Duke Realty Corp.	0.65	21.26
534	Peerless Mfg.	0.65	15.28
535	ConAgra Foods	0.65	9.31
536	Eastgroup Pptys Inc	0.65	19.64
537	X-Rite	0.65	0.35
538	Dentsply Int'l	0.65	21.26
539	Bush Inds.	0.65	15.34
540	Summa Inds Inc	0.65	7.93
541	GeoResources Inc	0.65	6.90
542	Monarch Services Inc	0.65	2.11
543	Providence & Worcester R R	0.65	9.04
544	Alliance Bancorp New	0.65	21.21
545	Philip Morris	0.65	12.55
546	Liberte Invs Inc Del	0.65	11.56
547	Slocan Forest Products	0.65	11.46
548	Boston Acoustics	0.65	1.71
549	Northrop Grumman	0.65	19.86
550	Gennum Corp.	0.65	27.86
551	Liberty Homes Inc.	0.65	1.72
552	Rocky Mountain Choc Factory	0.65	15.95
553	Amer. States Water	0.65	14.79
554	RPC Inc.	0.65	15.96
555	Cousins Propertys	0.65	18.02
556	Fresh Brands Inc	0.65	16.54
557	Archstone-Smith Tr.	0.65	18.03
558	BRE Properties	0.65	13.18
559	The Goldfarb Corporation	0.65	8.37

560	Seaboard Corp.	0.65	7.06		
561	Nitches Inc.	0.65	9.85		
562	CNS Inc.	0.65	18.06		
563	Roman Ltd Corp	0.65	5.07		
564	Cedar Fair L.P.	0.65	16.41		
565	Standard Register	0.65	10.96		
566	Amer. Nat'l Ins.	0.65	13.21		
567	Tootsie Roll Ind.	0.65	13.93	0.62	13.50
568	Badger Meter Inc.	0.65	18.06		
569	Lifeline Systems	0.65	18.58		
570	Kimco Realty	0.65	18.08		
571	Thor Inds.	0.65	18.20		
572	K-Swiss Inc.	0.65	16.79		
573	Aaron Rents Inc. 'A'	0.65	22.47		
574	Foster (L.B.) 'A'	0.65	5.26		
575	Westbank Corp	0.65	23.71		
576	II-VI	0.65	34.55		
577	F&M Bancorp Md.	0.65	12.25		
578	Enbridge Energy Partners LLP	0.65	16.74		
579	Kelly Services 'A'	0.65	3.17		
580	Southwest Gas	0.65	10.91		
581	FLANIGANS ENTERPRISES INC	0.65	23.85		
582	Penn Virginia Corp.	0.65	10.93		
583	AMCORE Financial	0.65	16.64		
584	Roanoke Elec. Steel	0.65	16.63		
585	Abington Bancorp	0.65	23.42		
586	Sturm Ruger & Co.	0.65	13.61		
587	Hunt Corp.	0.65	1.16		
588	Avatar Holdings	0.65	0.92		
589	First Fed Cap Corp	0.65	25.07		
590	Kansas City Life Ins	0.65	9.72		
591	Atlantic American Corp	0.65	6.04		
592	Ruddick Corp.	0.65	8.04		
593	Alcide Corp.	0.65	16.07		
594	1st Source Corp.	0.65	13.38		
595	Garan Inc.	0.65	12.86		
596	Oglebay Norton Co.	0.65	0.60		
597	Rowe Companies	0.65	14.08		
598	Presidential Life	0.65	19.25		
599	Quixote Corp.	0.65	5.53		
600	Cagle's Inc.	0.65	10.39		
601	Tetra Tech	0.65	21.69		
602	Campbell Soup	0.65	7.23		
603	Quaker Chemical	0.65	4.95		
604	TrustCo Bank of NY	0.65	22.95		

611	Cathay Bancorp	0.65	21.80
612	Rouse Co.	0.65	12.02
613	Tremont Corp.	0.65	5.62
614	Rent-A-Wreck of America	0.65	3.52
615	UST Inc.	0.70	7.35
616	Wendy's Int'l	0.70	13.28
617	California First Natl Bancorp	0.70	7.37
618	Butler Mfg.	0.70	13.34
619	Cara Operations Ltd	0.70	8.91
620	Gen'l Employment Ent.	0.70	13.14
621	United Industrial Corp.	0.70	13.47
622	UGI Corp.	0.70	11.91
623	ECC International	0.70	0.99
624	Kimberly-Clark	0.70	11.71
625	Mercury Air Group Inc.	0.70	13.71
626	Escalade Inc.	0.70	30.42
627	Kent Finl Svs Inc	0.70	11.47
628	ESPIRITO SANTO FINL ADR	0.70	14.25
629	TMBR/Sharp Drilling	0.70	39.89
630	Republic First Bancorp	0.70	11.64
631	Conmed Corp.	0.70	13.98
632	MEDICAL ACTION IND	0.70	12.81
633	Questar Corp.	0.70	14.28
634	Utd. Fire & Casualty	0.70	9.06
635	Universal Amern Finl Corp	0.70	28.75
636	Telecom N. Zealand ADS	0.70	12.75
637	Cameco Corporation	0.70	7.78
638	UniFirst Corp.	0.70	8.76
639	Technology Resh	0.70	1.65
640	Gen'l Dynamics	0.70	28.19
641	Matec Corp MD	0.70	1.08
642	Lazare Kaplan International In	0.70	1.23
643	Baldor Electric	0.70	14.44
644	Casey's Gen'l Stores	0.70	13.05
645	Torstar 'B'	0.70	11.97
646	Americas Car Mart Inc	0.70	41.07
647	Unico American Corp.	0.70	0.74
648	Brown & Brown Inc.	0.70	31.54
649	TVA Group Inc	0.70	1.13
650	Norsk Hydro ADR	0.70	8.76
651	Standex Int'l	0.70	7.82
652	Great West Lifeco Inc.	0.70	31.43
653	Banta Corp.	0.70	9.12
654	PepsiCo Inc.	0.70	13.92
655	Isomet Corp	0.70	1.23
656	Selective Ins. Group	0.70	15.93
657	Cogeco Inc.	0.70	14.76
658	Mego Financial Corp	0.70	8.08
659	Emco Limited	0.70	3.39
660	ServiceMaster Co.	0.70	16.01
661	Maritrans Inc.	0.70	21.53

662 Argonaut Group	0.70	3.35
663 Building Materials	0.70	8.36
664 Eagle Bancshares	0.70	23.67
665 First Cash Inc.	0.70	3.61
666 American Medical Alert	0.70	4.59
667 Gyrodyne Co Amer Inc	0.70	2.55
668 Southwestern Energy	0.70	4.84
669 ENDESA ADR	0.70	10.30
670 Independent Bank MA	0.70	25.34
671 Northeast Bancorp	0.70	15.59
672 Thomson Corp.	0.70	15.58
673 Dynamics Research Corp.	0.70	19.65
674 Maple Leaf Foods Inc.	0.70	2.50
675 CPAC Inc.	0.70	3.48
676 AG Services of America Inc.	0.70	8.60
677 RLI Corp.	0.70	19.06
678 Tembec Inc.	0.70	2.44
679 Haemonetics Corp.	0.70	9.77
680 ESCO Technologies Inc	0.70	24.03
681 Koger Equity Inc.	0.70	18.91
682 Washington Trst Bncp	0.70	24.05
683 Hanger Orthopedic Grp	0.70	2.74
684 Cascade Corp.	0.70	5.95
685 Summit Resources Ltd	0.70	11.00
686 BancorpSouth	0.70	16.55
687 Coastal Bancorp Inc	0.70	16.63
688 Team Inc.	0.70	2.76
689 PPL Corp.	0.70	9.99
690 Communication Sys.	0.70	5.99
691 Federal Rlty. Inv. Trust	0.70	9.77
692 Medford Bancorp Inc	0.70	24.51
693 Ryan's Family	0.70	10.41
694 Sico Inc.	0.70	8.61
695 Lindsay Mfg.	0.70	10.93
696 United Natl Bncrp NJ	0.70	19.04
697 E-L Finl Corp. Ltd.	0.70	10.84
698 Ceradyne Inc.	0.70	9.65
699 CVB Financial	0.70	25.93
700 Peoples Energy	0.70	10.25
701 Canadian Tire Corp. 'A'	0.70	4.32
702 Diagnostic Products	0.70	14.80
703 Neogen Corp.	0.70	17.42
704 WesBanco	0.70	10.62
705 Archer Daniels Midl'd	0.70	3.82
706 Masonite International Corp.	0.70	9.41
707 Nat'l Western Life	0.70	14.93
708 Integra Bank Corporation	0.70	10.63
709 BARRA Inc.	0.70	26.59
710 Starrett (L.S.)	0.70	1.87
711 G&K Services `A'	0.70	14.91
712 Canadian Western Bank	0.70	22.89

713 Edison Int'l	0.70	3.11		
714 DMI Furniture	0.70	1.80		
715 Quality Systems	0.70	27.56		
716 West Coast Bancorp	0.70	20.01		
717 Nexfor Inc.	0.70	4.35		
718 Grey Global Group Inc.	0.70	19.93		
719 Shaw Commun. 'B'	0.70	19.73		
720 First Charter Corp.	0.70	26.06		
721 Deb Shops	0.70	17.36		
722 MEDAMICUS INC	0.70	9.50		
723 Yocream Intl Inc	0.70	10.27		
724 Cache Inc.	0.70	2.13		
725 MITSUI & CO LTD	0.70	4.42		
726 Transatlantic Hldgs.	0.70	19.85		
727 GTC Transcon Gr 'B'	0.70	18.09		
728 Reynolds & Reynolds	0.70	19.93		
729 Scientific Technologies Inc.	0.75	10.66		
730 Energen Corp.	0.75	17.87		
731 Cott Corp.	0.75	13.36		
732 Paramount Resources Ltd.	0.75	22.62		
733 Luxottica Group ADR	0.75	23.01		
734 LoJack Corp	0.75	9.15		
735 Balchem Corp	0.75	18.17		
736 Nastech Pharm Co	0.75	34.32		
737 United Corporations Ltd.	0.75	13.24		
738 Toyota Motor ADR	0.75	10.60		
739 Watts Inds. 'A'	0.75	5.10		
740 Churchill Downs	0.75	8.64		
741 Sysco Corp.	0.75	18.49		
742 Ducommun Inc.	0.75	22.13		
743 Wrigley (Wm.) Jr.	0.75	18.51		
744 Concurrent Computer	0.75	5.35		
745 Nature's Sunshine	0.75	8.28		
746 Fuji Photo ADR	0.75	4.99		
747 Electro-Sensors	0.75	4.81		
748 Phillips Petroleum	0.75	12.96		
749 First Midwest Bncp.	0.75	18.90		
750 EDO Corp.	0.75	20.12		
751 CCBT Financial Cos	0.75	19.91		
752 Berkley (W.R.)	0.75	12.48		
753 Ameron Int'l	0.75	12.46		
754 Integral Systems	0.75	43.55		
755 Ivaco Inc.	0.75	4.31		
756 Intelligent Sys Corp.	0.75	7.67	0.69	13.30
757 Cubic Corp.	0.75	20.27		
758 Ruby Tuesday	0.75	20.22		
759 Corus Bankshares Inc	0.75	12.56		
760 Johnson & Johnson	0.75	20.38		
761 Penn West Petroleum Ltd.	0.75	52.19		
762 Alexander & Baldwin	0.75	3.84		
763 Commonwealth Telephone Entp.	0.75	20.63		

764	Castle (A.M.) & Co.	0.75	8.57
765	Lincoln Elec Hldgs.	0.75	20.66
766	Stryker Corp.	0.75	19.81
767	Tredegar Corp.	0.75	19.68
768	Whitney Holding	0.75	19.68
769	Pilgrim's Pride `B'	0.75	10.02
770	Chad Therapeutics	0.75	17.72
771	NL Industries	0.75	7.78
772	Sterling BanCorp.	0.75	21.72
773	Canadian 88 Energy Corp.	0.75	19.01
774	Prima Energy Corp.	0.75	37.01
775	Bio-Rad Labs 'B'	0.75	21.68
776	Vornado Realty Trust	0.75	21.63
777	State Auto Fin'l	0.75	19.39
778	Trustmark Corp.	0.75	19.39
779	BellSouth Corp.	0.75	12.60
780	Liberty Corp.	0.75	7.56
781	21st Century Ins. Group	0.75	0.58
782	Ohio Casualty	0.75	9.05
783	Cadmus Commun.	0.75	3.67
784	Sequa Corp. 'A'	0.75	3.72
785	Chesapeake Corp.	0.75	4.48
786	Regis Corp.	0.75	23.06
787	TSR INC	0.75	23.19
788	Alberto Culver 'A'	0.75	17.68
789	Repsol-YPF ADR	0.75	6.24
790	Intrawest Corporation	0.75	11.18
791	CACI International 'A'	0.75	28.44
792	Rogers Corp.	0.75	25.95
793	Immucor	0.75	2.40
794	Fulton Fin'l	0.75	15.83
795	Robbins & Myers Inc.	0.75	15.40
796	Sigma-Aldrich	0.75	8.72
797	First Years Inc.	0.75	15.75
798	MAF Bancorp	0.75	28.83
799	Atrion Corp	0.75	11.54
800	Brown Shoe	0.75	2.13
801	LSI Industries	0.75	29.64
802	SUPERVALU INC.	0.75	11.09
803	Standard Motor Prod.	0.75	6.07
804	Fred's Inc. 'A'	0.75	20.69
805	Commerce Bancshs.	0.75	15.95
806	Material Sciences	0.75	1.41
807	First Indiana Corp.	0.75	15.90
808	Rollins Inc.	0.75	2.55
809	Baxter Int'l Inc.	0.75	15.32
810	SBC Communications	0.75	9.46
811	Centennial Bancorp.	0.75	26.22
812	Moog Inc. 'A'	0.75	30.29
813	Intertape Polymer Group Inc.	0.75	9.38
814	AEP Industries	0.75	14.95

815 Western Gas Res.	0.75	7.99
816 Supreme Inds Inc.	0.75	11.39
817 Medicore Inc.	0.75	1.84
818 NUI Corp.	0.75	8.75
820 Potash Corp.	0.75	14.80
821 Citizens Banking	0.75	15.00
822 Safeway Inc.	0.75	27.00
823 Cascades Inc.	0.75	8.00
824 AMREP Corp.	0.75	2.04
825 Bob Evans Farms	0.75	6.86
826 Forest City Enterprs	0.75	26.36
827 Petro-Canada	0.75	14.43
828 Ashworth Inc.	0.75	1.72
829 Mid Atlantic Med Svc	0.75	26.63
830 Dole Food	0.75	1.89
831 RPM Inc.	0.75	9.45
832 Washington Post	0.75	11.44
833 Murphy Oil Corp.	0.75	14.05
834 Alfa Corp.	0.75	20.70
835 Universal Health Sv. `B'	0.75	30.40
836 Magnum Hunter Resources	0.75	9.75
837 Tenet Healthcare	0.75	17.31
838 MDS Inc	0.75	8.79
839 Markel Corp.	0.75	23.29
840 iDine Rewards Network	0.75	5.67
841 ShawCor Ltd. A	0.75	17.30
842 Samuel Manu-Tech Inc.	0.75	7.24
843 Oneida Ltd.	0.75	8.71
844 Alberto Culver 'B'	0.75	16.92
845 Jack in the Box	0.75	9.86
846 Osmonics Inc.	0.75	3.01
847 Sanderson Farms	0.75	13.48
848 Paxar Corp.	0.75	16.74
849 McGraw-Hill	0.75	17.53
850 Zenith Nat'l Ins	0.75	10.73
851 Triarc Cos. 'A'	0.75	11.85
852 Jean Coutu Group 'A'	0.75	17.49
853 Kirby Corp.	0.75	7.29
854 ProAssurance Corp.	0.75	13.47
855 ChevronTexaco	0.75	13.47
856 Nova Chemicals Corp	0.75	5.58
857 Granite Construction	0.75	13.75
858 Foothill Independent BanCorp.	0.75	16.86
859 Toro Co.	0.75	16.21
860 Modtech Hldgs Inc.	0.75	16.35
861 First Essex Bancorp.	0.75	30.85

866	Herley Inds.	0.75	16.41
867	Hawthorne Fin'L Corp.	0.75	2.89
868	Gallagher (Arthur J.)	0.75	24.03
869	Vital Signs	0.75	5.78
870	Amer. Science & Eng. Inc.	0.75	13.87
871	Knight Ridder	0.80	9.90
872	Wackenhut	0.80	11.64
873	Skyline Corp.	0.80	10.63
874	Noble Energy	0.80	10.66
875	Gehl Co	0.80	12.23
876	Ametek Inc.	0.80	11.11
877	Respironics Inc.	0.80	11.57
878	Longs Drug Stores	0.80	8.39
879	Dofasco	0.80	10.75
880	Apogee Enterprises	0.80	11.02
881	RARE Hospitality	0.80	8.24
882	Florida East Coast	0.80	9.99
883	Occidental Petroleum	0.80	7.79
884	Adams Resources & Energy	0.80	10.38
885	Cavalier Homes Inc	0.80	8.95
886	Kaman Corp.	0.80	10.07
887	Modine Mfg.	0.80	9.08
888	Sceptre Investment Counsel	0.80	7.75
889	World Fuel Services	0.80	9.69
890	EMS Technologies Inc	0.80	11.28
891	Mylan Labs.	0.80	9.26
892	Inter Parfums Inc.	0.80	8.89
893	Marathon Oil Corp.	0.80	5.64
894	AmeriServ Finl Inc	0.80	1.76
895	Ionics Inc.	0.80	1.02
896	CLARCOR Inc.	0.80	14.22
897	Marcus Corp.	0.80	14.23
898	Overseas Shipholding	0.80	6.07
899	Wesco Financial Corp.	0.80	16.18
900	Mattel Inc.	0.80	6.96
901	Bradley Pharmaceuticals Inc.	0.80	18.85
902	Hubbell Inc 'A'	0.80	6.80
903	Shell Transport	0.80	14.52
904	ADVO Inc.	0.80	19.51
905	New Horizons Worldwide	0.80	0.94
906	Ferro Corp.	0.80	4.97
907	Holly Corp.	0.80	7.01
908	Oriental Finl Group	0.80	33.99
909	Lincare Holdings	0.80	33.20
910	Allergan Inc.	0.80	19.90
911	Citizens Communic.	0.80	0.88
912	Amerada Hess	0.80	7.00
913	Tejon Ranch Co.	0.80	5.36
914	Eateries Inc	0.80	0.92
915	BENETTON GROUP SPA ADR	0.80	6.01
916	TBC Corp.	0.80	2.62

917	Brown (Tom) Inc.	0.80	18.80		
918	Hillenbrand Inds.	0.80	6.68		
919	WSFS Finl Corp	0.80	29.96		
920	Kroger Co.	0.80	18.17		
921	Quebecor Inc.	0.80	1.65		
922	Int'l Flavors & Frag.	0.80	1.63		
923	ABM Industries Inc.	0.80	18.13		
924	Manor Care	0.80	15.45		
925	Carpenter Technology	0.80	5.26		
926	Susquehanna Bncshs.	0.80	15.75		
927	Harleysville Group	0.80	15.34		
928	Honda Motor ADR	0.80	15.64		
929	Linamar Machine Limited	0.80	18.21		
930	BHP Billiton Ltd. ADR	0.80	6.19		
931	Apache Corp.	0.80	15.40		
932	Beckman Coulter	0.80	18.65		
933	Abbott Labs.	0.80	14.80		
934	Gabelli Equity	0.80	15.01		
935	ONEOK Inc.	0.80	14.85		
936	Fair Isaac	0.80	29.84		
937	CVS Corp.	0.80	5.02		
938	Cotton States Life Ins	0.80	16.06		
939	Pharm. Resources Inc	0.80	15.05		
940	Oxford Inds.	0.80	5.07		
941	Kellwood Co.	0.80	6.53		
942	McGrath RentCorp	0.80	15.98		
943	Federal Signal	0.80	6.51		
944	Rank Group ADR	0.80	7.01		
945	PW Eagle Inc	0.80	19.93	0.77	13.39
946	Electro Rent Corp.	0.80	14.05		
947	Haverty Furniture	0.80	26.97		
948	Capstead Mtg. Corp.	0.80	5.55		
949	AZZ Inc.	0.80	21.63		
950	Atl. Tele- Network	0.80	3.64		
951	Leucadia National	0.80	17.76		
952	Winn-Dixie Stores	0.80	0.18		
953	Dundee BanCorp. 'A'	0.80	21.34		
954	Gillette	0.80	13.38		
955	S & T Bancorp	0.80	21.27		
956	Kimball Int'l 'B'	0.80	5.71		
957	Burlington Resources	0.80	3.42		
958	Tyson Foods 'A'	0.80	3.45		
959	Bio-Rad Labs. 'A'	0.80	23.57		
960	Becton Dickinson	0.80	17.17		
961	Guardian Capital Group 'A'	0.80	12.40		
962	Nissan Motor ADR	0.80	5.67		
963	Barnes Group	0.80	12.49		
964	ALLTEL Corp.	0.80	12.74		
965	Chattem Inc.	0.80	12.87		
966	PepsiAmericas Inc.	0.80	2.08		
967	McKesson Corp.	0.80	26.50		

968	First Comnwlth Fin'l	0.80	22.16
969	Guardian Cap Group Ltd	0.80	14.03
970	Wiley (John) Sons 'B'	0.80	27.74
971	First BanCorp PR	0.80	40.62
972	Ciprico Inc.	0.80	5.51
973	Cinram Intl Inc	0.80	5.44
974	Royal Dutch Petr.	0.80	13.80
975	Canadian Natural Resources	0.80	20.53
976	Franklin Bk N.A. Mich.	0.80	13.82
977	Cincinnati Financial	0.80	16.25
978	Clorox Co.	0.80	16.26
979	Video Display Corp.	0.80	4.14
980	Exxon Mobil Corp.	0.80	13.89
981	Pope & Talbot	0.80	0.77
982	GBC Bancorp	0.80	17.98
983	National Technical Systems	0.80	5.92
984	Astronics Corp	0.80	16.36
985	Dynatronics Corp	0.80	4.13
986	Stewart Info Svcs	0.80	13.60
987	Thomas Inds.	0.80	16.39
988	Southern Union	0.80	17.82
989	Aur Resources Inc.	0.80	7.19
990	Granite State Bankshares	0.80	27.28
991	Unitrin Inc.	0.80	13.69
992	DVI Inc.	0.85	5.30
993	Standard Microsystems	0.85	10.61
994	Swiss Helvetia Fund	0.85	9.54
995	Datascope Corp.	0.85	2.26
996	F.N.B. Corp.	0.85	17.40
997	Aberdeen Australia Fd.	0.85	5.55
998	Timberline Software	0.85	17.85
999	McDonald's Corp.	0.85	10.75
1000	Harland (John H.)	0.85	5.51
1001	CanWest Global Communications	0.85	19.30
1002	United Bkshrs W.Va.	0.85	18.56
1003	Matsushita Elec. ADR	0.85	2.94
1004	TEVA PHARMACEUTICAL INDS A	0.85	24.25
1005	Telephone & Data	0.85	10.17
1006	BEI Medical Systems	0.85	10.11
1007	Hansen Natural Corp	0.85	3.76
1008	Petroleum Development Corp.	0.85	23.46
1009	Fairfax Financial Holdings	0.85	21.70
1010	MacDermid Inc.	0.85	23.20
1011	Trans Lux Corp.	0.85	2.95
1012	Fuller (H.B.)	0.85	4.00
1013	Donnelley (R.R) & Sons	0.85	3.38
1014	GenCorp Inc.	0.85	3.30
1015	Riggs National Corp.	0.85	9.95
1016	Republic Bancorp	0.85	22.42
1017	Eastman Kodak	0.85	3.21
1018	Exploration Co	0.85	3.21

1019 Wallace Computer Serv.	0.85	8.71
1020 Bell Inds.	0.85	4.09
1021 Bluegreen Corp.	0.85	10.54
1022 Printronix Inc.	0.85	17.32
1023 Popular Inc.	0.85	18.70
1024 Dow Jones & Co.	0.85	8.40
1025 Avon Products	0.85	18.74
1026 Bowne & Co.	0.85	9.66
1027 Community Fst Bnkshr	0.85	19.10
1028 Chittenden Corp.	0.85	25.42
1029 American Med Sec Group Inc	0.85	2.55
1030 Forest Labs.	0.85	25.19
1031 BSB Bancorp	0.85	20.64
1032 Bard (C.R.)	0.85	10.29
1033 UnitedHealth Group	0.85	24.56
1034 Pall Corp.	0.85	2.64
1035 Deluxe Corp.	0.85	4.25
1036 Russ Berrie And Co.	0.85	10.25
1037 Donaldson Co.	0.85	20.64
1038 Lone Star Steakhouse	0.85	16.18
1039 Cerner Corp.	0.85	27.35
1040 Lilly (Eli)	0.85	17.31
1041 Kyocera Corp. ADR	0.85	8.13
1042 Phelps Dodge	0.85	0.72
1043 Valspar Corp.	0.85	13.42
1044 Heartland Express	0.85	11.84
1045 Amer. Greetings	0.85	0.61
1046 Advanced Environ Recycling Tec	0.85	0.65
1047 Fahnestock Viner 'A'	0.85	13.81
1048 Coca-Cola	0.85	11.57
1049 Cleveland-Cliffs	0.85	0.73
1050 Southwall Tech	0.85	7.81
1051 JLG Industries	0.85	32.66
1052 Barry (R.G.)	0.85	7.00
1053 Dress Barn	0.85	10.84
1054 URS Corp.	0.85	14.40
1055 Gen'l Amer. Invest	0.85	14.42
1056 CDI Corp.	0.85	13.42
1057 Merrimac Inds Inc.	0.85	8.96
1058 Tetra Technologies	0.85	13.38
1059 South Financial Grp Inc	0.85	14.48
1060 Lee Enterprises	0.85	12.86
1061 Precision Drilling Ltd.	0.85	47.50
1062 Genuine Parts	0.85	7.56
1063 Viad Corp.	0.85	7.50
1064 Potlatch Corp.	0.85	0.16
1065 Kerr-McGee Corp.	0.85	7.48
1066 Alcan Inc.	0.85	7.41
1067 Smith (A.O.) 'A'	0.85	12.87
1068 Delphax Technologies Inc	0.85	8.95
1069 LaBarge Inc.	0.85	7.78

1070 Dionex Corp.	0.85	13.02
1071 American Healthways Inc.	0.85	13.02
1072 J&J Snack Foods	0.85	13.02
1073 Gaylord Entertainm.	0.85	7.38
1074 Invacare Corp.	0.85	14.47
1075 Stifel Finanical Corp.	0.85	11.54
1076 Neurogen Corp	0.85	1.13
1077 Wyeth	0.85	14.64
1078 IPSCO Inc.	0.85	5.99
1079 Unocal Corp.	0.85	6.18
1080 Greif Bros. Corp.	0.85	8.03
1081 Coca-Cola Enterprises	0.85	16.10
1082 Wiley (John) & Sons	0.85	27.64
1083 O'Charleys Inc.	0.85	23.07
1084 CAE Inc.	0.85	16.39
1085 IHOP Corp.	0.85	16.34
1086 Pittston Co.	0.85	6.21
1087 Horace Mann Eductrs.	0.85	10.93
1088 Valley Natl Bancp NJ	0.85	16.51
1089 Rio Alto Exploration Ltd.	0.85	26.87
1090 Anadarko Petroleum	0.85	16.71
1091 SL Inds. Inc.	0.85	8.09
1092 First Finl Holdings	0.85	27.80
1093 LandAmerica Finl Group	0.85	15.82
1094 Allied Waste	0.85	3.15
1095 Panera Bread Company	0.85	15.42
1096 MTS Systems	0.85	6.43
1097 Culp Inc.	0.85	6.62
1098 Akzo Nobel NV ADR	0.85	11.25
1099 Regal-Beloit	0.85	15.04
1100 Total System Svcs.	0.90	25.08
1101 Colorado Medtech Inc.	0.90	29.57
1102 Roper Inds.	0.90	27.03
1103 Provident Bankshares	0.90	26.12
1104 Fidelity Nat'l Fin'l	0.90	23.46
1105 Commerce Bancorp NJ	0.90	31.55
1106 CKE Restaurants	0.90	9.24
1107 Oshkosh Truck	0.90	23.16
1108 Pep Boys	0.90	0.27
1109 Giant Industries	0.90	9.66
1110 SunGard Data Sys.	0.90	26.66
1111 Nordson Corp.	0.90	3.02
1112 Lubrizol Corp.	0.90	2.45
1113 Scudder New Asia Fund	0.90	2.25
1114 P.A.M. Transport Svcs	0.90	52.93
1115 Loews Corp.	0.90	9.20
1116 Applied Extrusion Tech.	0.90	0.30
1117 Quidel Corp.	0.90	2.29
1118 Paulson Capital	0.90	29.25
1119 Tri-Continental	0.90	8.71
1120 Forest Oil	0.90	8.81

1121	Cardinal Health	0.90	28.04		
1122	Crawford & Co. 'B'	0.90	2.70		
1123	Royal Bank of Canada	0.90	2.36		
1124	Laser-Pacific Media Corp.	0.90	0.66		
1125	Vector Group Ltd.	0.90	36.37		
1126	Pinnacle Entertainment Inc	0.90	2.62		
1127	Trans World Entertain	0.90	0.48		
1128	Barr Labs.	0.90	34.16		
1129	People's Bank	0.90	25.67		
1130	Curative Health Services	0.90	0.42		
1131	Union Pacific	0.90	2.77		
1132	TRANS INDS INC	0.90	9.35		
1133	Park-Ohio	0.90	2.34		
1134	GTSI Corp	0.90	0.33	0.85	13.07
1135	CIGNA Corp.	0.90	23.51		
1136	Bassett Furniture	0.90	0.83		
1137	Coachmen Ind.	0.90	18.08		
1138	Vulcan Materials	0.90	15.68		
1139	Catellus Development	0.90	6.70		
1140	EOG Resources	0.90	14.14		
1141	Texas Inds.	0.90	14.16		
1142	Lancer Corp.	0.90	14.18		
1143	Smith (A.O.)	0.90	14.20		
1144	Dreyer's Grand	0.90	14.27		
1145	Bank of Montreal	0.90	14.42		
1146	FirstMerit Corp.	0.90	14.61		
1147	Invivo Corp	0.90	6.53		
1148	TRC Cos.	0.90	11.35		
1149	Ball Corp.	0.90	14.07		
1150	Sprint Corp.	0.90	6.52		
1151	U.S. Cellular	0.90	6.36		
1152	Newell Rubbermaid	0.90	6.31		
1153	Hubbell Inc. 'B'	0.90	6.22		
1154	Commercial Metals	0.90	11.20		
1155	Westamerica Bancorp	0.90	22.03		
1156	Jacobs Engineering	0.90	11.07		
1157	Oshkosh B'Gosh 'A'	0.90	14.12		
1158	Merit Medical Systems	0.90	11.58		
1159	Werner Enterprises	0.90	11.05		
1160	Progress Software	0.90	11.87		
1161	Nexen Inc.	0.90	12.48		
1162	Superior Inds. Int'l	0.90	12.07		
1163	Dawson Geophysical Co.	0.90	7.40		
1164	Checkpoint Systems	0.90	13.14		
1165	Hologic Inc.	0.90	13.17		
1166	Nam Tai Electronics Inc.	0.90	13.34		
1167	Myers Inds.	0.90	11.88		
1168	Scholastic Corp.	0.90	13.69		
1169	3M Company	0.90	13.41		
1170	Spectrum Control Inc.	0.90	13.96		
1171	Engelhard Corp.	0.90	11.79		

1172 Valassis Commun	0.90	11.77
1173 Spain Fund	0.90	7.10
1174 Washington Federal	0.90	11.73
1175 Teleflex Inc.	0.90	13.82
1176 Harsco Corp.	0.90	11.68
1177 NIKE Inc. 'B'	0.90	13.89
1178 Oceaneering Int'l	0.90	6.02
1179 LML Payment Sys Inc	0.90	12.32
1180 Medstone Intl Inc.	0.90	6.00
1181 El Paso Corp.	0.90	20.20
1182 Liberty All-Star	0.90	10.31
1183 Eaton Corp.	0.90	10.30
1184 Pogo Producing	0.90	19.64
1185 Plains Resources	0.90	10.29
1186 Sonic Corp.	0.90	19.68
1187 Investors Group Inc.	0.90	20.09
1188 Hooper Holmes	0.90	20.85
1189 Hasbro Inc.	0.90	3.88
1190 Jefferson-Pilot Corp.	0.90	19.09
1191 Key Production Co.	0.90	20.87
1192 Air Methods Corp	0.90	3.76
1193 Genlyte Group	0.90	21.40
1194 Belo Corp. 'A'	0.90	10.03
1195 CompuCom Systems	0.90	3.54
1196 Comstock Resources	0.90	21.99
1197 Italy Fund	0.90	4.79
1198 Frontier Oil	0.90	19.40
1199 IDEXX Labs.	0.90	19.02
1200 Ecolab Inc.	0.90	18.96
1201 Nat'l Bank of Canada	0.90	18.87
1202 Scotts Co. 'A'	0.90	10.87
1203 Ashland Inc.	0.90	5.35
1204 Automatic Data Proc.	0.90	17.12
1205 Talisman Energy	0.90	17.04
1206 Kewaunee Scientific Corp.	0.90	5.69
1207 Florida Rock	0.90	17.97
1208 Sunoco Inc.	0.90	5.81
1209 TDK Corp. ADR	0.90	5.91
1210 Duratek Inc.	0.95	7.80
1211 Valero Energy	0.95	5.78
1212 Burlington Northern	0.95	7.62
1213 Stewart Enterpr. 'A'	0.95	3.76
1214 Playboy Enterprises 'B'	0.95	3.55
1215 Cooper Tire & Rubber	0.95	0.62
1216 Amer. Financial Group	0.95	5.62
1217 York Int'l	0.95	1.00
1218 Cabot Oil & Gas 'A'	0.95	7.83
1219 Hitachi Ltd. ADR	0.95	2.52
1220 UQM Technologies Inc.	0.95	0.84
1221 SENETEK PLC ADR	0.95	5.94
1222 Liz Claiborne	0.95	6.93

1223	Germany Fund	0.95	7.04
1224	Briggs & Stratton	0.95	8.52
1225	Templeton Emerg'g	0.95	5.15
1226	Sonoco Products	0.95	7.74
1227	Richardson Elec.	0.95	5.42
1228	Kaydon Corp.	0.95	8.63
1229	Wilmington Trust	0.95	12.52
1230	Pitney Bowes	0.95	12.81
1231	Aon Corp.	0.95	13.53
1232	Merck & Co.	0.95	10.82
1233	Swift Energy	0.95	13.41
1234	PolyMedica Corp	0.95	21.63
1235	Gen'l Communication 'A'	0.95	21.47
1236	Cambrex Corp.	0.95	26.14
1237	Golden West Fin'l	0.95	18.02
1238	Gannett Co.	0.95	13.56
1239	Brinker Int'l	0.95	12.97
1240	GATX Corp.	0.95	10.55
1241	Assoc. Banc-Corp	0.95	13.88
1242	Griffon Corp	0.95	11.96
1243	HON Industries Inc.	0.95	14.02
1244	Cato Corp.	0.95	14.18
1245	Reliability Inc.	0.95	14.19
1246	Hovnanian Enterpr. 'A'	0.95	10.84
1247	IndyMac Bancorp Inc.	0.95	25.71
1248	Protective Life	0.95	20.68
1249	Bank of Nova Scotia	0.95	22.66
1250	BankUnited Finl Corp	0.95	11.61
1251	AMC Entertainment	0.95	12.14
1252	Lakeland Ind	0.95	22.76
1253	Meridian Resource Corp	0.95	11.56
1254	PXRE Group Ltd.	0.95	12.21
1255	Amgen	0.95	22.72
1256	Berkshire Hathaway	0.95	23.21
1257	Sears Canada Inc.	0.95	12.86
1258	BioSource Intl Inc.	0.95	18.53
1259	Syncor Int'l	0.95	12.45
1260	Colgate-Palmolive	0.95	17.64
1261	Fiserv Inc.	0.95	25.05
1262	Downey Financial	0.95	21.96
1263	Cullen/Frost Bankers	0.95	21.93
1264	TRW Inc.	0.95	10.37
1265	Applebee's Int'l	0.95	26.75
1266	La-Z-Boy Inc.	0.95	16.30
1267	St. Jude Medical	0.95	12.04
1268	Amer. Woodmark	0.95	33.65
1269	Omnicare Inc.	0.95	19.56
1270	Fannie Mae	0.95	19.68
1271	Media General 'A'	0.95	15.26
1272	Teamstaff Inc	0.95	15.05
1273	First Va. Banks	0.95	15.10

1274	Ackerley Group	0.95	34.39		
1275	Parallel Petrol.	0.95	16.20		
1276	Eaton Vance Corp.	0.95	34.67		
1277	Air Products & Chem.	0.95	9.50		
1278	Fortune Brands	0.95	9.31		
1279	V.F. Corp.	0.95	9.34		
1280	Doral Fin'l Corp	0.95	36.36		
1281	Hughes Supply	0.95	19.38		
1282	Adams Express	0.95	9.88		
1283	HCA Inc.	0.95	14.80		
1284	Misonix Inc.	0.95	15.48		
1285	Old Republic	0.95	15.74		
1286	Avery Dennison	0.95	19.27		
1287	Outback Steakhouse	0.95	18.31		
1288	Graco Inc.	0.95	28.79		
1289	U I C I	0.95	20.00		
1290	DIANON Systems	0.95	18.93		
1291	Sherwin-Williams	0.95	9.17		
1292	Airgas Inc.	0.95	18.10		
1293	Biogen Inc.	1.00	22.05		
1294	Amer. Mgmt. Sys.	1.00	12.14		
1295	HEI INC	1.00	12.69		
1296	Mentor Corp.	1.00	22.65		
1297	Miller (Herman)	1.00	19.45		
1298	IDEX Corp.	1.00	15.84		
1299	Salomon Bros. Fund	1.00	12.64		
1300	Media 100 Inc	1.00	3.36		
1301	Bristol-Myers Squibb	1.00	7.74		
1302	Volvo AB ADR	1.00	5.52		
1303	Analysts Int'l	1.00	4.65		
1304	Domtar Inc.	1.00	7.36		
1305	Tidewater Inc.	1.00	12.90		
1306	Computer Sciences	1.00	14.81		
1307	Watsco Inc.	1.00	20.97		
1308	NACCO Inds. 'A'	1.00	4.41		
1309	Research Frontiers	1.00	14.05		
1310	AutoZone Inc.	1.00	14.65		
1311	Commercial Federal	1.00	21.20		
1312	Craftmade International	1.00	20.69		
1313	Ryder System	1.00	4.13		
1314	USA Education	1.00	20.48		
1315	CBRL Group	1.00	3.76		
1316	SouthTrust Corp.	1.00	19.81		
1317	Albany Int'l 'A'	1.00	4.58		
1318	Mercantile Bankshares	1.00	14.49		
1319	Pfizer Inc.	1.00	21.81		
1320	N.Y. Times	1.00	12.98		
1321	Meredith Corp.	1.00	21.68		
1322	Sony Corp. ADR	1.00	13.23		
1323	Theragenics Corp.	1.00	18.03	0.94	13.75
1324	Helmerich & Payne	1.00	15.11		

1325 Biomet	1.00	13.52
1326 HEICO Corp.	1.00	16.34
1327 Hibernia Corp. `A'	1.00	20.06
1328 Quanex Corp.	1.00	6.08
1329 Excel Technology	1.00	16.40
1330 Carlton ADR	1.00	1.89
1331 Zions Bancorp.	1.00	26.02
1332 Stelco Inc. 'A'	1.00	1.20
1333 Millipore Corp.	1.00	8.66
1334 Walgreen Co.	1.00	26.04
1335 Alpha Technologies Grp.	1.00	2.43
1336 Stanley Works	1.00	10.62
1337 Dow Chemical	1.00	8.06
1338 NEC Corp. ADR	1.00	0.93
1339 Emerson Electric	1.00	9.83
1340 CECO Environmental	1.00	2.27
1341 Weyerhaeuser Co.	1.00	8.27
1342 Polaris Inds.	1.00	25.37
1343 Spartech Corp	1.00	28.60
1344 Cooper Cos.	1.00	17.40
1345 Allou Health & Beauty'A'	1.00	1.74
1346 Bemis Co.	1.00	10.06
1347 Health Mgmt. Assoc.	1.00	26.65
1348 Range Resources Corp.	1.00	1.47
1349 Winnebago	1.00	26.45
1350 Manpower Inc.	1.00	10.53
1351 REX Stores Corp	1.00	17.45
1352 Johnson Controls	1.00	17.39
1353 Intermet Corp.	1.00	2.44
1354 Swift Transportation	1.00	23.44
1355 Lincoln Nat'l Corp.	1.00	17.22
1356 Webster Fin'l	1.00	23.18
1357 Paychex Inc.	1.00	39.99
1358 Henry (Jack) & Assoc.	1.00	39.30
1359 Activision Inc.	1.00	11.69
1360 MSC.Software	1.00	3.05
1361 Washington Mutual	1.05	18.95
1362 United Stationers	1.05	28.68
1363 Colonial BncGrp. 'A'	1.05	18.11
1364 Bowater Inc.	1.05	9.13
1365 CNA Fin'l	1.05	0.03
1366 Vodafone Group ADR	1.05	15.62
1367 Chronimed Inc.	1.05	4.34
1368 Computer Task Group	1.05	1.57
1369 Tribune Co.	1.05	15.89
1370 Maxwell Technologies Inc.	1.05	5.16
1371 Aztar Corp.	1.05	14.61
1372 Pemco Aviation Group Inc	1.05	28.08
1373 QLT Inc.	1.05	16.30
1374 Medtronic Inc.	1.05	27.98
1375 Zebra Techn. 'A'	1.05	20.66

1376	Cintas Corp.	1.05	18.76
1377	Westcorp	1.05	14.92
1378	Diebold Inc.	1.05	16.20
1379	Onex Corp.	1.05	29.53
1380	Cyanotech Corp.	1.05	6.43
1381	ClearOne Commmunications Inc	1.05	37.22
1382	SAFECO Corp.	1.05	6.34
1383	OSI Pharmaceuticals	1.05	19.59
1384	Rohm and Haas	1.05	8.76
1385	North Fork Bancorp	1.05	38.89
1386	Systems & Comp. Tech	1.05	16.70
1387	Cadiz Inc	1.05	9.27
1388	AutoNation Inc.	1.05	15.29
1389	Spherix Inc.	1.05	6.91
1390	Mission Resources Corp	1.05	0.07
1391	CTC Communications Group	1.05	9.94
1392	Bombardier 'A'	1.05	32.10
1393	Concerto Software Inc	1.05	19.86
1394	Snap-on Inc.	1.05	5.23
1395	Carlisle Cos.	1.05	15.54
1396	Nautica Enterprises	1.05	18.33
1397	Illinois Tool Works	1.05	17.30
1398	National City Corp.	1.05	15.08
1399	Int'l Business Mach.	1.05	15.53
1400	St. Paul Cos.	1.05	14.40
1401	THQ Inc.	1.05	3.07
1402	Methode Elec.	1.05	10.21
1403	SEA CONTAINERS LTD 'B'	1.05	2.64
1404	Mercury General	1.05	23.97
1405	PPG Inds.	1.05	7.58
1406	Freddie Mac	1.05	22.15
1407	Lands' End	1.05	11.24
1408	AEGON Ins. Group	1.05	25.29
1409	Titan Corp	1.05	22.24
1410	Rexhall Ind	1.05	12.70
1411	Elcor Corp.	1.05	21.94
1412	Deere & Co.	1.05	12.76
1413	Bombardier Inc. 'B'	1.05	23.90
1414	AFLAC Inc.	1.05	23.84
1415	Nucor Corp.	1.05	10.26
1416	Pioneer-Standard	1.05	17.77
1417	Lafarge No. America	1.05	11.99
1418	USFreightways	1.05	11.60
1419	Du Pont	1.05	7.86
1420	SPS Technologies	1.05	11.55
1421	Block (H&R)	1.05	12.33
1422	Electronic Data Sys.	1.05	7.94
1423	Synovus Financial	1.05	23.09
1424	Clayton Homes	1.05	11.50
1425	Mentor Graphics	1.05	3.24
1426	Williams Cos.	1.05	16.97

1427	Disney (Walt)	1.05	7.47
1428	First Rep Bk San Francisco	1.05	12.88
1429	City National Corp.	1.05	18.00
1430	Int'l Paper	1.05	3.11
1431	Union Planters	1.05	13.94
1432	Ross Stores	1.05	26.95
1433	Possis Medical	1.05	5.97
1434	AmSouth Bancorp.	1.05	14.11
1435	Drexler Technology Corp.	1.05	14.10
1436	Temple-Inland	1.05	2.06
1437	Nuevo Energy	1.05	3.96
1438	Compass Bancshares	1.05	17.43
1439	Parker-Hannifin	1.05	14.19
1440	White Electronic Designs Corp	1.05	26.27
1441	Applied Innovation	1.05	21.37
1442	MBIA Inc.	1.05	7.33
1443	CenturyTel Inc.	1.05	10.80
1444	Toronto-Dominion	1.05	21.80
1445	Techne Corp.	1.05	26.07
1446	Norfolk Southern	1.05	2.33
1447	Huntington Bancshs.	1.05	12.41
1448	Waste Management	1.05	8.19
1449	First Amer Corp	1.05	21.43
1450	Burlington Coat	1.05	10.55
1451	Humana Inc.	1.10	5.54
1452	U.S. Bancorp	1.10	18.46
1453	Amtech Systems Inc	1.10	18.00
1454	Toll Brothers	1.10	17.56
1455	Pulte Homes	1.10	18.22
1456	Harrah's Entertain.	1.10	17.40
1457	Zarlink Semiconductor Inc.	1.10	17.96
1458	First Albany Cos.	1.10	8.87
1459	May Dept. Stores	1.10	8.98
1460	Reebok Int'l	1.10	2.05
1461	SPX Corp.	1.10	22.99
1462	MICROS Systems	1.10	23.00
1463	MGIC Investment	1.10	24.06
1464	Softnet Sys Inc	1.10	2.45
1465	Resource America Inc.	1.10	26.26
1466	TCF Financial	1.10	27.33
1467	DeVry Inc.	1.10	27.20
1468	Andrea Electronics	1.10	3.38
1469	Banknorth Group	1.10	27.65
1470	Cognos	1.10	35.12
1471	NBTY Inc.	1.10	41.11
1472	Yellow Corp.	1.10	0.07
1473	Lyondell Chemical	1.10	0.03
1474	Whole Foods Market	1.10	22.25
1475	Hudson United Bancorp	1.10	21.87
1476	Nortek Inc.	1.10	22.14
1477	AAR Corp.	1.10	4.93

1478	Parlex Corp.	1.10	19.63		
1479	Can. Imperial Bank	1.10	19.00		
1480	Korea Fund	1.10	4.80		
1481	Ambac Fin'l Group	1.10	19.25		
1482	Volt Info. Sciences	1.10	19.27		
1483	Cummins Inc.	1.10	4.72		
1484	K-V Pharmaceutical	1.10	20.05		
1485	BB&T Corp.	1.10	20.03		
1486	MGM Mirage	1.10	21.45		
1487	NS Group	1.10	4.31		
1488	Trimble Nav. Ltd.	1.10	4.26		
1489	Thermo Electron	1.10	3.91		
1490	Southwest Airlines	1.10	21.35		
1491	CSX Corp.	1.10	3.65		
1492	Schering-Plough	1.10	17.01		
1493	Banco Bilbao Vis. ADR	1.10	18.77		
1494	Tesoro Petroleum	1.10	9.48		
1495	CNF Inc.	1.10	5.95		
1496	Sierra Health Svcs.	1.10	10.56		
1497	ShopKo Stores	1.10	5.74		
1498	Schlumberger Ltd.	1.10	7.58		
1499	Elan Corp. ADR	1.10	12.59		
1500	Offshore Logistics	1.10	9.46		
1501	Alcoa Inc.	1.10	15.04		
1502	Genzyme Corp.	1.10	15.22		
1503	Chubb Corp.	1.10	11.10		
1504	Input/Output	1.10	10.50		
1505	FirstFed Fin'l-CA	1.10	9.93		
1506	Timken Co.	1.10	9.74		
1507	SunTrust Banks	1.10	15.52		
1508	Torchmark Corp.	1.10	9.70		
1509	Boeing	1.10	9.16		
1510	Harris Corp.	1.10	11.97		
1511	Brunswick Corp.	1.10	6.71		
1512	Energy Conversion	1.10	10.66	1.06	14.53
1513	Four Seasons Hotels	1.10	16.03		
1514	Int'l Game Tech.	1.10	16.65		
1515	Symbol Technologies	1.10	12.97		
1516	Mesaba Holdings	1.10	16.61		
1517	Chiron Corp.	1.10	14.39		
1518	California Amplifier Inc.	1.10	6.89		
1519	Sealed Air	1.10	13.18		
1520	Big Lots Inc.	1.10	5.86		
1521	Gen'l Motors	1.10	7.25		
1522	Grainger (W.W.)	1.10	9.45		
1523	Computer Ntwrk Tech	1.15	10.17		
1524	Thomas & Betts	1.15	0.75		
1525	Telefonica SA ADR	1.15	15.23		
1526	Dycom Inds.	1.15	18.88		
1527	Rowan Cos.	1.15	15.23		
1528	InterVoice-Brite Inc.	1.15	9.37		

1529	Amer Tech Ceramics	1.15	21.33
1530	Norstan Inc.	1.15	1.28
1531	Baker Hughes	1.15	7.68
1532	Genus Inc.	1.15	6.34
1533	Tech Data	1.15	19.43
1534	Dover Corp.	1.15	15.59
1535	Hilton Hotels	1.15	3.73
1536	Comerica Inc.	1.15	15.33
1537	Delphi Fin'l `A'	1.15	19.14
1538	Whirlpool Corp.	1.15	7.23
1539	Goodrich Corp.	1.15	4.47
1540	Molex Inc.	1.15	15.20
1541	Textron Inc.	1.15	12.65
1542	Callaway Golf	1.15	20.20
1543	Andrew Corp.	1.15	20.17
1544	Varco International Inc.	1.15	12.76
1545	Black & Decker	1.15	7.56
1546	Wells Fargo	1.15	20.54
1547	Park Electrochemical	1.15	22.14
1548	Precision Castparts	1.15	14.67
1549	AGF Management Ltd. 'B'	1.15	33.60
1550	KCS Energy	1.15	13.05
1551	Michaels Stores	1.15	12.45
1552	Lone Star Techn.	1.15	19.94
1553	Vicor Corp.	1.15	4.16
1554	PerkinElmer Inc.	1.15	3.34
1555	Pentair Inc.	1.15	14.95
1556	Interface Inc. 'A'	1.15	3.31
1557	Interpublic Group	1.15	13.48
1558	Sharper Image	1.15	19.62
1559	Jones Apparel Group	1.15	20.35
1560	Impco Technologies Inc	1.15	13.78
1561	Family Dollar Stores	1.15	20.93
1562	K V Pharmaceutical 'A'	1.15	18.76
1563	C & D Technologies	1.15	27.28
1564	Nabi Biopharmaceuticals	1.15	5.92
1565	Fifth Third Bancorp	1.15	24.97
1566	Caterpillar Inc.	1.15	16.16
1567	Air Canada	1.15	1.83
1568	Criticare Systems	1.15	2.58
1569	Wal-Mart Stores	1.15	16.37
1570	Brazil Fund	1.15	5.32
1571	Right Start Inc.	1.15	1.39
1572	Alliance Capital Mgmt.	1.15	28.36
1573	Crane Co.	1.15	11.09
1574	Centennial Communications Corp	1.15	5.89
1575	Kennametal Inc.	1.15	10.89
1576	Jaco Electrs Inc	1.15	17.88
1577	UNUMProvident Corp.	1.15	6.05
1578	Trinity Inds.	1.15	5.83
1579	Comcast Corp.	1.15	18.51

1580	Harman Int'l	1.15	27.76
1581	Wireless Telecom.	1.15	18.70
1582	M.D.C. Holdings	1.15	37.56
1583	Mediware Info Syst	1.15	9.14
1584	KeyCorp	1.15	11.47
1585	MGI Pharma	1.15	1.32
1586	Concord Camera	1.15	10.55
1587	Timberland Co. 'A'	1.15	27.68
1588	Saks Inc.	1.15	11.45
1589	PACCAR Inc.	1.15	16.09
1590	Mexico Fund	1.20	1.81
1591	FleetBoston Fin'l	1.20	12.70
1592	Dollar General Corp.	1.20	26.37
1593	News Corp. Ltd. ADR	1.20	10.15
1594	Noble Corp.	1.20	31.40
1595	Supertex Inc.	1.20	12.90
1596	Astec Inds.	1.20	27.58
1597	Manitowoc Co.	1.20	21.81
1598	Omnicom Group	1.20	27.32
1599	HEALTHSOUTH Corp.	1.20	10.21
1600	Sybase Inc.	1.20	0.95
1601	Microsoft Corp.	1.20	27.53
1602	Bel Fuse Inc.	1.20	10.43
1603	Fremont Gen'l	1.20	8.45
1604	Isis Pharmac.	1.20	3.32
1605	DPAC Technologies Corp	1.20	10.50
1606	Autodesk Inc.	1.20	8.29
1607	WMS Industries	1.20	1.38
1608	Handleman Co.	1.20	1.39
1609	Anixter Int'l	1.20	12.39
1610	Quiksilver Inc.	1.20	29.73
1611	CyberOptics	1.20	12.17
1612	Mellon Financial Corp.	1.20	22.38
1613	Insituform Techn.	1.20	2.92
1614	Catalina Marketing	1.20	23.20
1615	PNC Financial Serv.	1.20	11.49
1616	Immunomedics	1.20	2.76
1617	BJ Services	1.20	28.97
1618	Owens-Illinois	1.20	2.10
1619	Federated Dept. Stores	1.20	11.59
1620	Progressive (Ohio)	1.20	26.22
1621	Georgia-Pacific Group	1.20	0.26
1622	Unisys Corp.	1.20	2.45
1623	Osteotech Inc.	1.20	3.31
1624	WPP Group ADR	1.20	28.72
1625	Gilead Sciences	1.20	25.57
1626	Unit Corp.	1.20	25.19
1627	Nabors Inds.	1.20	22.20
1628	Symmetricom Inc.	1.20	5.72
1629	Cooper Inds.	1.20	1.72
1630	G-III Apparel Group Ltd	1.20	0.49

1631	Boise Cascade	1.20	6.04
1632	Esterline Technologies	1.20	16.37
1633	Frequency Electrs Inc.	1.20	17.41
1634	Applica Inc	1.20	5.94
1635	Sears Roebuck	1.20	14.42
1636	Artesyn Technologies Inc	1.20	8.84
1637	Hewlett-Packard	1.20	6.71
1638	FedEx Corp.	1.20	20.15
1639	Leggett & Platt	1.20	16.60
1640	Nordstrom Inc.	1.20	5.17
1641	Masco Corp.	1.20	9.11
1642	Phoenix Technologies	1.20	4.88
1643	ValueVision Int'l	1.20	33.15
1644	Claire's Stores	1.20	19.87
1645	United Technologies	1.20	20.84
1646	Limited Inc.	1.20	7.01
1647	Regeneron Pharmac.	1.20	4.59
1648	Banco Santander ADR	1.20	14.27
1649	Rainbow Technologies	1.20	3.91
1650	Vintage Petroleum	1.20	16.02
1651	Halliburton Co.	1.20	5.57
1652	Terex Corp.	1.20	5.12
1653	Marsh & McLennan	1.20	17.81
1654	Genesco Inc.	1.20	16.22
1655	Gentex Corp.	1.25	27.07
1656	Whitman ED Group	1.25	5.56
1657	Northern Trust Corp.	1.25	19.47
1658	Microsemi Corporation	1.25	31.04
1659	Bank of New York	1.25	24.60
1660	Iomega Corp.	1.25	16.44
1661	Key Energy Services Inc.	1.25	8.62
1662	Avnet Inc.	1.25	7.89
1663	Dana Corp.	1.25	2.75
1664	Atwood Oceanics	1.25	24.31
1665	Coherent Inc.	1.25	17.95
1666	SBS Technologies	1.25	15.86
1667	Danaher Corp.	1.25	28.32
1668	Westwood One	1.25	34.84
1669	Countrywide Credit	1.25	15.55
1670	Geac Computer Corp. Ltd.	1.25	4.50
1671	Alliance Gaming Corp	1.25	22.31
1672	Seitel Inc.	1.25	8.49
1673	Cohu Inc.	1.25	36.27
1674	Siliconix	1.25	36.79
1675	Ocean Energy	1.25	5.67
1676	ENSCO Int'l	1.25	27.78
1677	Bank One Corp.	1.25	7.15
1678	Amer. Power Conv.	1.25	13.58
1679	Neiman Marcus	1.25	11.08
1680	Symantec Corp.	1.25	5.13
1681	Centex Corp.	1.25	17.16

1682	Hunt (J.B.)	1.25	2.19		
1683	Mandalay Resort Group	1.25	1.12		
1684	NVR Inc.	1.25	35.83		
1685	Amer. Int'l Group	1.25	23.24		
1686	Mueller Inds.	1.25	25.28		
1687	TJX Companies	1.25	28.71		
1688	Harley-Davidson	1.25	31.27		
1689	Christopher & Banks Corp	1.25	41.34		
1690	Grey Wolf Inc.	1.25	18.65		
1691	VISX Inc.	1.25	17.89		
1692	Wet Seal `A'	1.25	18.02		
1693	Robert Half Int'l	1.25	37.19		
1694	Helen of Troy Ltd.	1.25	6.00		
1695	Intel Corp.	1.30	32.83		
1696	Wolverine World Wide	1.30	24.33		
1697	Office Depot	1.30	10.73		
1698	Three-D Systems	1.30	10.84		
1699	Target Corp.	1.30	25.79		
1700	PacifiCare Health	1.30	2.46		
1701	Fastenal Co.	1.30	26.21	1.19	14.78
1702	Tyco Int'l Ltd.	1.30	16.20		
1703	Computer Horizons	1.30	10.05		
1704	Honeywell Int'l	1.30	11.27		
1705	Qualcomm Inc.	1.30	36.76		
1706	ICOS Corp.	1.30	11.87		
1707	Comtech Telecomm.	1.30	11.46		
1708	Vertex Pharmac.	1.30	13.45		
1709	Pride Intl Inc	1.30	17.46		
1710	Insignia Systems	1.30	4.34		
1711	Presstek Inc.	1.30	4.31		
1712	Cognex Co.	1.30	20.12		
1713	Standard Pacific Corp.	1.30	14.51		
1714	Keane Inc.	1.30	21.73		
1715	AES Corp.	1.30	3.59		
1716	Gen'l Electric	1.30	19.86		
1717	AnnTaylor Stores	1.30	9.85		
1718	Cadence Design Sys.	1.30	13.45		
1719	Scientific Games Corp.	1.30	10.21		
1720	Scios Inc.	1.30	8.77		
1721	Pier 1 Imports	1.30	20.73		
1722	Provident Finl Group	1.30	13.60		
1723	Newpark Resources	1.30	14.92		
1724	Maytag Corp.	1.30	10.90		
1725	Electronic Arts	1.30	26.37		
1726	ICN Pharmaceuticals	1.30	7.92		
1727	Ryland Group	1.30	19.60		
1728	Reuters ADR	1.30	5.07		

1733	Intermagnetics Gen'l	1.30	23.00
1734	Cypress Semiconductor	1.35	16.40
1735	Navistar Int'l	1.35	1.63
1736	Household Int'l	1.35	26.27
1737	RadioShack Corp.	1.35	17.40
1738	Alaska Air Group	1.35	5.47
1739	Viacom Inc. 'B'	1.35	10.49
1740	Salton Inc.	1.35	17.82
1741	Sotheby's Holdings 'A'	1.35	1.86
1742	CTS Corp.	1.35	17.48
1743	Oracle Corp.	1.35	40.75
1744	Alkermes Inc.	1.35	11.83
1745	Bank of America	1.35	15.10
1746	Celgene Corp.	1.35	19.41
1747	C-COR.net Corp	1.35	15.24
1748	Lowe's Cos.	1.35	34.06
1749	SEI Investments	1.35	30.79
1750	Starwood Hotels	1.35	31.14
1751	National Semiconductor	1.35	12.62
1752	Tektronix Inc.	1.35	14.95
1753	IDEC Pharmac.	1.35	44.84
1754	Innovex Inc.	1.35	19.93
1755	Datum Inc.	1.35	14.88
1756	KB Home	1.35	12.67
1757	Best Buy Co.	1.35	46.64
1758	Expeditors Int'l	1.35	32.46
1759	Int'l Rectifier	1.35	23.77
1760	Nu Horizons Electronics Corp.	1.35	21.40
1761	Hughes Electronics	1.35	8.79
1762	Interactive Data Corp	1.35	36.04
1763	Ingersoll-Rand	1.35	10.91
1764	Synopsys Inc.	1.35	11.39
1765	Electro Scientific	1.40	32.90
1766	Circuit City Group	1.40	9.85
1767	Mtr Gaming Group Inc	1.40	17.22
1768	Three-Five Sys.	1.40	28.54
1769	State Street Corp.	1.40	20.68
1770	Atrix Labs	1.40	14.16
1771	FileNET Corp.	1.40	3.95
1772	Franklin Resources	1.40	17.94
1773	Diodes Inc.	1.40	36.60
1774	Clear Channel	1.40	42.69
1775	ImClone Systems	1.40	11.04
1776	Keithley Instruments	1.40	18.48
1777	Acxiom Corp.	1.40	23.49
1778	SkyWest	1.40	41.81
1779	Cephalon Inc.	1.40	17.79
1780	Sepracor Inc.	1.40	11.40
1781	Advanta Corp. 'A'	1.40	2.78
1782	InFocus Corp.	1.40	10.04
1783	Lennar Corp.	1.40	25.59

1784	Noven Pharm.	1.40	10.85
1785	Integrated Device	1.45	28.29
1786	Adobe Systems	1.45	22.64
1787	Pre-Paid Legal Services	1.45	38.40
1788	Hutchinson Techn.	1.45	7.74
1789	Benchmark Elec.	1.45	16.03
1790	Arrow Electronics	1.45	11.55
1791	Raymond James Fin'l	1.45	18.75
1792	MasTec Inc.	1.45	18.79
1793	Price (T. Rowe) Group	1.45	24.72
1794	Computer Associates	1.45	15.65
1795	Scientific Atlanta	1.45	22.55
1796	MedImmune Inc.	1.45	21.52
1797	Edwards (A.G.)	1.45	16.13
1798	Adaptec Inc.	1.45	13.54
1799	Airborne Inc.	1.45	10.50
1800	Exar Corp.	1.45	17.18
1801	Nokia Corp. ADR	1.45	52.48
1802	Concord EFS	1.45	41.71
1803	SWS Group Inc	1.45	16.86
1804	MBNA Corp.	1.50	33.08
1805	Staples Inc.	1.50	22.56
1806	Home Depot	1.50	21.41
1807	Dell Computer	1.50	51.70
1808	Semtech Corp.	1.50	62.33
1809	Aspect Communications	1.50	10.40
1810	Enzo Biochem	1.50	19.45
1811	Amer. Express	1.50	22.16
1812	Cisco Systems	1.50	39.76
1813	Champion Enterprises	1.50	19.23
1814	BMC Software	1.50	8.60
1815	Cendant Corp.	1.50	11.31
1816	Mesa Air Group	1.50	2.09
1817	Orbotech Ltd.	1.50	18.58
1818	Carnival Corp.	1.50	17.92
1819	Sun Microsystems	1.50	25.40
1820	Protein Design	1.50	25.67
1821	Morgan (J.P.) Chase	1.50	18.41
1822	Emisphere Tech. Inc.	1.50	0.69
1823	Applied Biosystems	1.50	8.57
1824	Cirrus Logic	1.50	2.87
1825	Photronics Inc.	1.50	23.82
1826	Koninklijke Philips NV	1.50	21.02
1827	Helix Technology	1.50	29.45
1828	Genome Therapeutics Inc.	1.55	6.61
1829	Oxford Health Plans	1.55	34.68
1830	Vishay Intertechnology	1.55	17.99
1831	Xicor	1.55	20.63
1832	Lattice Semiconductor	1.55	15.44
1833	Glenayre Tech.	1.55	1.66
1834	Bear Stearns	1.55	20.91

1835	Linear Technology	1.55	32.36
1836	Zygo Corp.	1.55	23.48
1837	Newport Corp.	1.55	24.33
1838	Citigroup Inc.	1.55	29.86
1839	Immunex Corp.	1.55	27.81
1840	Inter-Tel	1.55	30.74
1841	Legg Mason	1.55	23.71
1842	Silicon Valley Bncsh	1.55	28.04
1843	ADC Telecom.	1.60	16.42
1844	Tiffany & Co.	1.60	22.95
1845	EMC Corp.	1.60	42.45
1846	Maxim Integrated	1.60	39.69
1847	Alpha Industries	1.60	26.19
1848	Netegrity Inc.	1.60	15.40
1849	Williams-Sonoma	1.60	33.63
1850	Xilinx Inc.	1.60	32.17
1851	Ericsson ADR	1.60	14.60
1852	BE Aerospace Inc.	1.60	1.42
1853	Gap (The) Inc.	1.60	9.79
1854	Ascential Software	1.60	2.61
1855	Nanometrics Inc	1.60	34.48
1856	Technitrol Inc.	1.65	28.44
1857	Solectron Corp.	1.65	17.60
1858	FSI Int'l	1.65	15.71
1859	Western Digital	1.65	11.42
1860	Applied Materials	1.65	45.04
1861	Kulicke & Soffa	1.65	21.93
1862	Texas Instruments	1.65	31.45
1863	Altera Corp.	1.65	31.87
1864	LSI Logic	1.65	21.56
1865	AOL Time Warner	1.70	70.68
1866	Advanced Micro Dev.	1.70	1.38
1867	Tekelec	1.70	17.60
1868	Medarex Inc.	1.70	10.06
1869	Tellabs Inc.	1.70	23.99
1870	KLA-Tencor	1.75	39.48
1871	Analog Devices	1.75	35.12
1872	Novellus Sys.	1.75	39.36
1873	Comverse Technology	1.75	16.30
1874	Plexus Corp.	1.75	19.02
1875	Robotic Vision Sys.	1.75	2.82
1876	LTX Corp.	1.75	27.48
1877	Lam Research	1.75	25.95
1878	NTL Inc.	1.80	26.09
1879	Rational Software	1.80	18.67
1880	Micron Technology	1.80	32.21
1881	Teradyne Inc.	1.80	23.82
1882	Enzon Inc.	1.85	16.71
1883	Merrill Lynch & Co.	1.85	23.08
1884	Emulex Corp.	1.85	30.74
1885	Atmel Corp.	1.85	32.36

1886 PMC-Sierra	1.90	21.82		
1887 Vitesse Semiconductor	1.90	12.45		
1888 Safeguard Scientifics	1.95	14.47		
1889 Schwab (Charles)	1.95	29.49		
1890 AmeriCredit Corp.	1.95	38.87	1.48	20.78
1891 DMC Stratex Networks Inc	2.00	1.95		

		Beta	Return 10-Y	Fitted	CAPM
Portfolio	1	0.41	10.87	11.62	8.69
Portfolio	2	0.54	12.02	12.17	9.66
Portfolio	3	0.62	13.50	12.53	10.31
Portfolio	4	0.69	13.30	12.85	10.88
Portfolio	5	0.77	13.39	13.18	11.46
Portfolio	6	0.85	13.07	13.51	12.06
Portfolio	7	0.94	13.75	13.91	12.77
Portfolio	8	1.06	14.53	14.42	13.68
Portfolio	9	1.19	14.78	15.01	14.73
Portfolio	10	1.29		15.44	15.50
Portfolio	11	1.39		15.88	16.27
Portfolio	12	1.49		16.31	17.05
Portfolio	13	1.59		16.75	17.82
Portfolio	14	1.69		17.18	18.60
Portfolio	15	1.79		17.62	19.37
Portfolio	16	1.89		18.05	20.15
Portfolio	17	1.99		18.49	20.92

Rm	13.24
Rf	5.50
MRP	7.74

Regression Output:		
Constant		9.830233
Std Err of Y Est		0.540422
R Squared		0.822748
No. of Observations		9
Degrees of Freedom		7
X Coefficient(s)	4.347298	
Std Err of Coef.	0.762663	

DOD/HECO-IR-3-38

Please provide a complete copy of Dr. Morin's workpapers and articles cited in his Testimony not otherwise requested in the above interrogatories.

Dr. Morin's Response:

Other than the materials provided in the responses to the above interrogatories, the data in Dr. Morin's exhibits are constructed from commercially available information services obtained on a paid subscription basis on CD-ROMs updated monthly, primarily the Value Line Investment Analyzer. The information contained in the Value Line Investment Analyzer software cannot be supplied electronically in order to avoid violation of copyright laws. Material that is proprietary can be made available for inspection upon reasonable prior notice at the Company's premises. Dr. Morin notes that much of the information contained in the Value Line Investment Analyzer software is available in paper format from the latest edition of the traditional Value Line Investment Survey coinciding with the month of publication of the software version. Such reports are available at most university libraries in paper format.

Analysts' growth forecasts are obtained directly online from Zacks Investment Research Web site and are available by commercial paid subscription to members. Material that is proprietary can be made available for inspection upon reasonable prior notice at the Company's premises.

Copies of the Moody's (now Mergent) Public Utility Manual reference cited in the footnotes of Exhibit HECO-2002 are available in most respectable libraries and regulatory commission libraries. The bond yields were obtained from Ibbotson Associates "Yearbook" of historical returns, Table B-6 "Long-Term Government Bond Yields". This widely used reference is available by paid commercial subscription only and cannot be disseminated without violating copyright laws, and can certainly be made available for inspection upon reasonable prior notice at the Company's premises.

DOD/HECO-IR-3-39

[Gnechten Direct, p. 3, ll. 10-15]

[illegible]

Hawaiian Electric Company, Inc.

COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 1995 Average

	(A)	(B)	(C)	(D)
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Requirements	Weighted Earnings Requirements (B) x (C)
Short-Term Debt	$47,328	5.46	5.00%	0.27%
Long-Term Debt	336,210	38.76	7.13%	2.76%
Preferred Stock	60,525	6.98	7.28%	0.51%
Common Equity	423,414	48.81	13.00%	6.35%
Total	$867,477	100.00		
Estimated Test Year Composite Cost of Capital				9.89%

NOTE: NUMBERS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaiian Electric Company, Inc.

COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 1994 Average

	(A)	(B)	(C)	(D)
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Requirements	Weighted Earnings Requirements (B) x (C)
Short-Term Debt	$45,240	5.56	4.00%	0.22%
Long-Term Debt	315,019	38.68	7.04%	2.72%
Preferred Stock	59,582	7.32	7.30%	0.53%
Common Equity	394,492	48.44	12.75%	6.18%
Total	$814,333	100.00		
Estimated Test Year Composite Cost of Capital				9.66%

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaiian Electric Company, Inc.

COMPOSITE EMBEDDED COST OF CAPITAL
Estimated 1992 Average

	(A)	(B)	(C)	(D)
	Capitalization			
	Amount in Thousands	Percent of Total	Earnings Requirements	Weighted Earnings Requirements (B) x (C)
Short-Term Debt	$35,620	5.41	5.00%	0.27%
Long-Term Debt	250,352	38.04	7.79%	2.96%
Preferred Stock	61,396	9.33	7.41%	0.69%
Common Equity	310,823	47.22	13.50%	6.38%
Total	$658,191	100.00		
Estimated Test Year Composite Cost of Capital				10.30%

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

DOD/HECO-IR-3-40

[Gnechten Direct, p. 6, ll. 6, 7]
In Mr. Gnechten's experience, has HECO ever been unable to access the debt market? If so, please provide any available evidence that such an event occurred.

HECO Response:

Mr. von Gnechten was the Financial Vice President for HECO from 2000 to 2004, and he is not aware of HECO being unable to access the debt market during this period. However, during the 9/11 crisis, HECO was cut off from the commercial paper market (not due to lack of financial integrity) and had to borrow money from Bank of Hawaii instead. This experience across the industry caused the rating agencies to ask what alternatives companies had in the event of such a situation and demonstrates the need to maintain financial integrity in order to have ready access to alternative sources of funds.

DOD/HECO-IR-3-41

[Gnechten Direct, pp. 8, 9]
Are HECO's construction plans for additional generation and transmission infrastructure extraordinary, when compared to industry averages? Please provide support for your response.

HECO Response:

Mr. von Gnechten is not aware of industry averages for forecast capital expenditures.

DOD/HECO-IR-3-42

[Gnechten Direct, p. 10, ll. 9-12]

a. Has the Hawaii Public Utilities Commission ("Commission") provided regulatory support in the past for HECO's CHP investments?

b. Does the Company have reason to believe that the Commission's position on CHP or DSM programs in the future will be different that it has been in the past? If so, please provide evidence to support the Company's concerns for the future.

HECO Response:

a. The Commission has not, as yet, provided either approval or disapproval of HECO's CHP efforts and investments. On October 10, 2003, HECO, together with MECO and HELCO, filed an application in Docket No. 03-0366 for approval of a utility-owned CHP Program and Schedule CHP tariff, under which the utilities would provide CHP services to eligible commercial customers. By Order No. 20582, filed October 21, 2003, Docket No. 03-0371, the Commission initiated a proceeding to investigate and examine the potential benefits and impacts of distributed generation ("DG") on Hawaii's electric distribution system and market. In Order No. 20831, issued on March 2, 2004, the PUC suspended HECO, MECO, and HELCO's application for the Utility CHP program until, at the minimum, the matters in Docket No. 03-0371 have been addressed, indicating that Docket No. 03-0371 is intended to "form the basis for rules and regulations deemed necessary to govern participation into Hawaii's electricity market through distributed generation." Similarly, the Commission by Order Nos. 21554 and 21555, (Docket Nos. 04-0366 and 04-0314) issued on January 21, 2005, suspended its review of two applications (one by HECO and one by HELCO) for individual utility CHP projects until the issues of Docket No. 03-0371 are addressed. (HECO's CHP agreement was then terminated by the customer, and HECO withdrew its application in Docket No. 04-0314.)

b. As described in subpart a above, the Commission is currently considering the issues of the generic investigative docket on DG in Docket No. 03-0371. A threshold issue of the docket will be to consider HECO's ability to offer utility-owned CHP systems to its customers as a regulated service. Thus, the Commission's position on utility-owned CHP will be defined in the future.

The Commission has not stated that its position on DSM programs will be any different than in the past, but the Commission's Decision and Order No. 21698, dated March 16, 2005, provides an indication that it is not committed to the same approach to DSM that it pursued in the past. The D&O separated the DSM Programs from this rate case and opened an Energy Efficiency Docket (Docket No. 05-0069). Among the issues identified by the Commission in the D&O are:

1. Whether energy efficiency goals should be established and if so, what the goals should be for the State;
2. Whether the seven (7) proposed DSM programs, the RCEA program, and/or other energy efficient programs will achieve the established energy efficiency goals and whether the programs will be implemented in a cost-effective manner;
3. What market structure(s) is the most appropriate for providing these or other DSM programs (e.g., utility-only, utility in competition with non-utility providers, non-utility providers);
4. For utility-incurred costs, what cost recovery mechanism(s) is appropriate (e.g., base rates, fuel clause, IRP Clause); and
5. For utility-incurred costs, what cost level is appropriate?

Thus, it is clear that the potential certainly exists for a DSM program future that is significantly different from current circumstances.

DOD/HECO-IR-3-43

[Gnechten Direct, p. 11]
Is it Mr. Gnechten's belief that the Commission is likely to disallow RE investments that have been mandated by the State Legislature? If so, please provide any available evidence that would lead to such a belief.

HECO Response:

No, Mr. von Gnechten cannot predict how the Commission will treat renewable energy investments made; however, legally-required compliance has typically been covered in rates. (It should be noted that the State Legislature has not mandated specific RE investments in specific RE projects.)

DOD/HECO-IR-3-44

[Gnechten Direct, p. 12, ll. 11, 12]

Please explain how the ECAC "substantially reduces the Company's risk with regard to fuel oil prices." Please also explain how purchased power energy costs are recovered under the ECAC.

HECO Response:

1. Refer to HECO T-10, page 68, lines 10 through 21 for explanation of how the ECAC reduces the Company's risk with regard to fuel oil prices.
2. Refer to HECO T-10, Energy Cost Adjustment Clause pages 67 through 72, Exhibits HECO-1030, HECO-1031 and HECO-1032 and workpapers HECO-WP-1032 on how purchased energy costs are recovered through ECAC.

DOD/HECO-IR-3-45

[Gnechten Direct, p. 12, ll. 11-19]

If the Company is made whole for purchased power costs under the ECAC, and the ECAC is continued by the Commission, please explain how the Company is at risk for unexpected changes in purchase power costs other than through the dissolution of the ECAC.

<u>HECO Response:</u>

As discussed in the pages in HECO T-10 referred to in response to DOD/HECO-IR-3-44 with respect to costs recovered through ECAC due to changes in fuel oil prices and purchased energy costs, HECO is not made whole for purchased power costs under the ECAC. Moreover, the potential for dissolution of the ECAC entirely represents a significant risk. In 1997 PUC

decisions approving the electric utilities' fuel supply contracts, the PUC noted that, in light of the length of the fuel supply contracts and the relative stability of fuel prices, the need for continued use of ECAC would be the subject of investigation in a generic docket or in a future rate case. These clauses were continued in the most recent HELCO and MECO rate cases (final D&O's issued in February 2001 and April 1999, respectively). The electric utilities reached agreement with their suppliers on amendments to their existing fuel supply contracts that extend the contracts through December 2014 on substantially the same terms and conditions, including market-related pricing. In December 2004, the PUC approved the amendments to the fuel supply contracts. In approving the amendments, the PUC indicated questions still remain concerning ECAC and their continued use to recover fuel contract costs, and indicated that, consistent with recovered in their base rates. If ECAC were discontinued, the electric utilities' results of operations could fluctuate significantly as a result of increases and decreases in fuel oil and purchased energy prices. Currently, recovery of purchased energy costs through the ECAC is a consideration that reduces the risk factor assigned by S&P for HECO's contracts to 30%. S&P has indicated that the risk factor it assigns to purchase power contracts when purchase power cost recovery is solely through base rates would be 50%. So, if ECAC were eliminated, HECO would likely see the risk factor assigned to its purchase power contracts increase from 30% to 50% and the imputed debt assigned by S&P would increase proportionately.

DOD/HECO-IR-3-46

[Gnechten Direct, p. 13]
Please provide any studies undertaken by or for the Company regarding the probability that the US military bases in Hawaii will be shut down.

HECO Response:

There are none.

DOD/HECO-IR-3-47

[Gnechten Direct, p. 13, ll. 6-12]
Please cite to any instance in which the Commission has disallowed the cost of pollution control equipment.

HECO Response:

HECO is not aware of any instance in which the Commission has disallowed the cost of pollution control equipment.

DOD/HECO-IR-3-48

[Gnechten Direct, p. 12, ll. 21, 22]
Is it also true for depreciation expense, taxes and corporate overhead that those expenses must be paid "before shareholders receive any compensation for the use of their funds?" If not, please explain why not.

<u>HECO Response:</u>

Taxes and corporate overhead are expenses that must be paid before shareholders receive compensation for the use of their funds. Depreciation expense is a non-cash item. Conceptually, revenue to recover depreciation expense is a mechanism for return of investment to shareholders (as well as other investors). Depreciation is a deduction in arriving at net income (return on shareholders' investment).

DOD/HECO-IR-3-49

[Gnechten Direct, p. 14, ll. 4-6]
What GAAP principles have changed that "may impact the financial statement presentation" of purchased power contracts? Please provide support for your response.

HECO Response:

The most significant changes in GAAP principles potentially affecting the financial statement presentation of purchase power contracts are EITF 01-8 and FIN 46R as discussed on pages 18 to 22 of HECO T-21.

DOD/HECO-IR-3-50

[Gnechten Direct, p. 15, ll. 13, 14]
Please explain how "consideration of a competitive bidding requirement" could "significantly impact HECO's financial performance." Provide actual examples from Company experience.

HECO Response:

If competitive bidding for new generation significantly impacts the market in which the Company operates, the ability of the Company to make new generation investments or its ability to earn a return on those investments, it could significantly impact HECO's financial performance. A competitive bidding evaluation structure which fails to consider all the costs associated with purchased power contracts could result in higher costs of electricity. Avoided cost calculations of purchase power contracts currently do not take into consideration the debt-like features of long-term, fixed payment obligations embedded in certain purchase power agreements (PPA). This results in an understatement of the costs associated with the PPA (or overstatement of the costs avoided by the contract). Recent changes to the accounting standards applicable to PPAs (such as FIN 46R and EITF 01-8) may worsen the situation if the changes result in investors perceiving greater risks associated with the contracts and requiring higher returns for investments in the utility. In addition to the direct financial costs of the PPA and the financial costs of incurring a long-term obligation, there are other indirect operational costs which must be considered in evaluating competitive bids. These costs also have the potential to impact the long-term financial performance of the Company. The Company's position on competitive bid considerations was filed in Docket No. 03-0372.

DOD/HECO-IR-3-51

[Gnechten Direct, p. 18, ll. 12-20]

a. Please provide evidence from the Company's records or those of any other electric utility that purchased power agreements similar to those utilized by HECO have been considered to be a "lease" and included as debt capital on the balance sheet of the firm.

b. If the regulators already consider PPA's when setting the allowed return and regulatory capital structure (i.e., they consider PPA's to be additional debt), please explain why recording the PPA's as debt on the balance sheet would increase financial risk.

HECO Response:

a. Please see attached excerpt from HECO's 10K filing for the period ended December 31, 2004.

HECO is not aware of any utilities currently capitalizing purchase power agreements. Please note that EITF 01-8 applies to arrangements agreed to or committed to, if earlier, after the beginning of an entity's reporting period beginning after May 28, 2003. Reassessment of arrangements that were in existence prior to EITF 01-8 is triggered only under specific circumstances. Further, we note that the isolated power market and limited heavy industries in Hawaii may make it more likely that lease accounting treatment may be triggered. As stated in the KPMG publication "Lease Arrangements Have Broadened" on HECO-2113 p.2:

> "An arrangement is a lease or contains an embedded lease if it conveys the right to control the use of property, plant, or equipment (collectively, the "property")

the mainland. As noted in the testimony and in the 10K, HECO has determined that it does

not take substantially all the output of the Kalaeloa contract due to Kalaeloa's steam sales to

The following is an excerpt from HECO's 10K filing for the year ended 12/31/04, p. 102:

Determining whether an arrangement contains a lease. In May 2003, the FASB ratified Emerging Issues Task Force (EITF) Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease." Under EITF Issue No. 01-8, companies may need to recognize service contracts, such as power purchase agreements for energy and capacity, or other arrangements as leases subject to the requirements of SFAS No. 13, "Accounting for Leases." The Company adopted the provisions of EITF Issue No. 01-8 in the third quarter of 2003. Since EITF Issue No. 01-8 applies prospectively to arrangements agreed to, modified or acquired after June 30, 2003, the adoption of EITF Issue No. 01-8 had no effect on the Company's historical financial statements. If any new power purchase agreement or a reassessment of an existing agreement required under certain circumstances (such as in the event of a material amendment of the agreement) falls under the scope of EITF Issue No. 01-8 and SFAS No. 13, and results in the classification of the agreement as a capital lease, a material effect on the Company's financial statements may result, including the recognition of a significant capital asset and lease obligation.

In October 2004, Kalaeloa and HECO executed two amendments to their PPA under which, if PUC approval is obtained and other conditions are satisfied, Kalaeloa may make an additional 29 MW of firm capacity available to HECO. HECO reassessed the PPA under EITF Issue No. 01-8 due to the amendments and determined that the PPA does not contain a lease because HECO does not control or operate Kalaeloa's property, plant or equipment and another party is purchasing more than a minor amount of the output.

DOD/HECO-IR-3-52

[Gnechten Direct, pp. 19, 20]

a. Who was the primary beneficiary of the Trusts? Why?

b. By "deconsolidated" does witness Gnechten mean that the QUIPS were removed from the balance sheet of HECO? If "yes," did that lower the debt on HECO's balance sheet; if "no," please explain why HECO's balance sheet did not change.

c. Please explain how PPA's could be considered to be a "variable interest entity."

HECO Response:

a. HECO determined that it is not the primary beneficiary of the Trust because it does not hold a majority of the variable interests in the Trust. The holders of the Trust's Cumulative Quarterly Income Preferred Securities are the primary beneficiaries of the Trust because they as a group absorb a majority of the exposure to the Trust's expected losses, if they occur, or the right to receive the Trust's expected residual returns, if they occur, or both. If any one security holder in the group held a majority of the variable interests, that holder would be deemed the primary beneficiary. If no security holder held a majority of the variable interests, there would be no primary beneficiary.

b. Prior to the adoption of FIN 46R, the trusts which existed for the purpose of issuing cumulative quarterly income preferred securities ("QUIPS") and investing the proceeds in QUIDS issued by HECO were consolidated by HECO for financial reporting purposes. HECO reflected the QUIPS for consolidated financial reporting purposes. "Deconsolidation" refers to the fact that for financial reporting after January 1, 2004 (with

QUIDS). For consolidated financial statement reporting purposes, there was an increase in

long term debt and decrease in preferred securities of trust subsidiaries. Since balances for ratemaking purposes are based on HECO's general ledger balances (not consolidated financial statements), there was no impact for ratemaking purposes.

c. Under FIN 46R, an "entity" is any legal structure used to conduct activities or to hold assets. The seller in a purchase power agreement may be an entity. "Variable interests" are contractual, ownership, or other pecuniary interest in an entity that change with changes in the fair value of the entity's net assets exclusive of variable interests. The PPA may be a variable interest in a variable interest entity.

DOD/HECO-IR-3-53

[Gnechten Direct, p. 21, l. 14]
Is interest expense related to the Kalaeloa PPA included in the Company's income tax calculation? If so, please provide support for your response. If not, why not?

HECO Response:

No, the "interest expense" related to the Kalaeloa PPA that is discussed in the testimony is not actual interest expense. It is not included in the company's income tax calculation. It is an amount imputed by S&P for purposes of adjusting financial ratios and determination of HECO's credit rating.

DOD/HECO-IR-3-54

[Gnechten Direct, p. 22, ll. 9-19]

[redacted]

of the Kalaeloa PPA-related debt capital, how the amount of that debt was calculated, and what HECO's "target" debt ratio is.

b. If the bond rating agencies already impute debt related to the PPA's, please explain why any "re-balancing" would be necessary in order to retain the same financial strength rating.

HECO Response:

further review of the calculations, corrections were made. The testimony should have stated that HECO estimates that it would need to retire approximately $65 million in order to maintain its test year average equity ratio rather than $70 million.

Estimated impacts based on both the debt ratio and the equity ratio were provided to give a range of potential impacts. While S&P and Moody's consider the debt ratio as one of the measures they monitor, they have also consistently emphasized the importance of maintaining equity levels of the Company as a critical element of maintaining a strong balance sheet in order to maintain the Company's credit ratings.

At the time direct testimony was prepared, Series 1993 ($50 million) and 1995A ($40 million) revenue bonds were the only outstanding redeemable long-term debt. (Series 1995A has since been redeemed.)

- Page 7 (attached) shows the calculation of test year average composite cost of capital assuming: 1) redeeming the Series 1995A revenue bonds which would result in a test year average composite cost of capital of 9.19% and 2) redeeming both the Series 1993 and 1995A revenue bonds which would result in a test year average cost of capital of 9.33%. Calculations based on the test year average impact were provided; however, note that the year-end impact would be greater.
- Page 8 (attached) shows the calculation of the test year average revenue requirement impact of redeeming the Series 1995A revenue bonds of $2.7 million.
- Page 9 (attached) shows the calculation of the test year average revenue requirement impact of redeeming both the Series 1993 and 1995A revenue bonds of $6.4 million.

b. The debt currently imputed by the rating agencies will likely differ from the debt and equity which would be added to the company's financial statement in a consolidation. If the debt and equity added in consolidation results in a higher debt ratio, the company may need to retire existing debt and increase equity in order to maintain its original debt ratio.

Rate Case w/ & w/o Kalaeloa Consolidation

	Status Quo				
	2005 Test Year Average Note (1)	Percent of Total	Earnings Requirement Note (1)	Weighted Earnings Requirement	Revenue Requirement
Short-Term Debt	39,929	3.47%	3.50%	0.12%	3.84%
Long-Term Debt	424,262	36.85%	6.30%	2.32%	6.91%
Hybrid Securities	27,303	2.37%	7.55%	0.18%	8.29%
Preferred Stock	20,476	1.78%	5.54%	0.10%	9.95%
Common Equity	639,455	55.54%	11.50%	6.39%	20.66%
Total Capitalization	1,151,425	100.00%		9.11%	

Tax Assumptions:

Federal	35.00%	32.89%
State	6.40%	6.02%
		38.91%
Public Service Company Tax		5.885%
PUC Fee		0.500%
Franchise Tax		2.500%
Revenue Tax Rate		8.885%

Note (1): Per Docket No. 04-0113 HECO-2101.

Pages 5 and 6 intentionally left blank.

Rate Case w/ & w/o Kalaeloa Consolidation

	Status Quo *					Redeem 1995A Only **					Redeem 1993 and 1995A ***				
	Test Year 2005 Average	Percent of Total	Earnings Requirement	Weighted Earnings Requirement	Revenue Requirement	Test Year 2005 Average	Percent of Total	Earnings Requirement	Weighted Earnings Requirement	Revenue Requirement	Test Year 2005 Average	Percent of Total	Earnings Requirement	Weighted Earnings Requirement	Revenue Requirement
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Short-Term Debt	39,929	3.47%	3.47%	0.12%	3.81%	39,929	3.47%	3.50%	0.12%	3.84%	39,929	3.47%	3.50%	0.12%	3.84%
Long-Term Debt	424,262	36.85%	6.30%	2.32%	6.91%	404,075	35.09%	6.29%	2.21%	6.90%	379,068	32.92%	6.35%	2.09%	6.97%
Hybrid Securities	27,303	2.37%	7.55%	0.18%	8.29%	27,303	2.37%	7.55%	0.18%	8.28%	27,303	2.37%	7.55%	0.18%	8.28%
Preferred Stock	20,476	1.78%	5.54%	0.10%	6.08%	20,476	1.78%	5.54%	0.10%	6.08%	20,476	1.78%	5.54%	0.10%	6.08%
Common Equity	639,455	55.54%	11.50%	6.39%	20.66%	659,641	57.29%	11.50%	6.59%	20.66%	684,648	59.46%	11.50%	6.84%	20.66%
Total Capitalization	1,151,425	100.00%		9.11%		1,151,424	100.00%		9.19%		1,151,424	100.00%		9.33%	

Tax Assumptions:

Federal	35.00%	32.89%
State	6.40%	6.02%
		38.91%
Public Service Company Tax		5.885%
PUC Fee		0.500%
Franchise Tax		2.500%
Revenue Tax Rate		8.885%

* Please refer to HECO-2101 page 1 for original cost of capital schedule and notes. Notes presented below represent new or revised information

** See pages 10-15 for recalculation of test year average and earnings requirement for Series 1995A redemption.

*** See pages 16-21 for recalculation of test year average and earnings for Series 1993 and 1995A redemptions.

Pages 8 and 9 intentionally left blank.

Hawaiian Electric Company, Inc.

Embedded Cost of Long-Term Debt
Test Year 2005 Average
($ Thousands)

Long-Term Debt	(A) Rate	(B) Net Proceeds	(C) = (A)*(B) Annual Interest	(D) = DOD-IR-3-54, page 12 Annual Amortization	(E) = (C)+(D) Annual Requirement
Special Purpose Revenue Bonds (Refunded Issue):					
Series 1993	5.45%	$ 50,000	$ 2,725	$ 89	$ 2,814
Series 1995A **	6.60%	20,000	1,320	103	1,423
Series 1996A	6.20%	48,000	2,976	79	3,055
Series 1996B	5 7/8%	14,000	823	19	842
Series 1997A	5.65%	50,000	2,825	71	2,896
Refunding Series 1998A (1987)	4.95%	42,580	2,108	254	2,362
Refunding Series 1999B (1988)	5.75%	30,000	1,725	118	1,843
Series 1999C	6.20%	35,000	2,170	63	2,233
nding Series 1999D (1990A)	6.15%	16,000	984	49	1,033
.unding Series 2000 (1990B&C)	5.70%	46,000	2,622	181	2,803
Series 2002A	5.10%	33,644	1,716	106	1,822
Refunding Series 2003B (1992)	5.00%	40,000	2,000	195	2,195
Unamortized Costs, Revenue Bonds *		(20,371)			
Unamortized Costs, First Mtg Bonds		(779)		103	103
Test Year 2005 Average		**$ 404,075**	**$ 23,993**	**$ 1,430**	**$ 25,423**
Effective Rate = Total(E)/Total(B)					**6.29%**

Please refer to HECO-2103 page 1 for original schedule and notes. Notes presented below represent new or revised information.

* Issuance costs, redemption costs, issuance discounts, and investment income differentials are included in this amount. Refer to page 12 for detail.

** Series 1995A early redeemed on January 1, 2005. Refer to page 10 for calculation of 2005 average balance.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Early Redemption of Series 1995A Special Purpose Revenue Bonds

	Total	
Outstanding Series 1995A as of December 31, 2003	$ 40,000,000	
2004 Activity	-	
Outstanding Series 1995A as of December 31, 2004	40,000,000	(A)
Early Redemption on January 1, 2005 *	(40,000,000)	
Outstanding Series 1995A as of December 31, 2005	$ -	(B)
:st Year 2005 Average = [(A)+(B)]/2	**$ 20,000,000**	

* Per bond documents, HECO can early redeem the Series 1995A bonds beginning January 1, 2005 at a 101% redemption price.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Revenue Bonds
Summary of Unamortized Balances

Unamortized Costs	WP Reference	(A) 12/31/03 Unamortized Balance	(B) 12/31/04 Unamortized Balance	(C) 12/31/05 Unamortized Balance
	DOD-IR-3-54			
Issuance and Redemption	p. 14	$ 14,997,484	$ 14,073,928	$ 13,509,666
	HECO-WP-2103			
Investment Income Differential	p. 8	3,775,594	4,082,968	3,976,771
	HECO-WP-2103			
Issuance Discount	p. 10	2,744,287	2,615,035	2,483,242
Total		$ 21,517,365	$ 20,771,932	$ 19,969,679
Test Year 2005 Average = [Total(B)+Total(C)]/2				**$ 20,370,805**

Please refer to HECO-WP-2103 page 2 for original schedule and notes.

Totals may not add due to rounding

Hawaiian Electric Company, Inc.

Revenue Bonds
Summary of 2005 Annual Amortizations

	(A) = DOD-IR-3-54, page 14	(B) = HECO-WP-2103, page 8	(C) = HECO-WP-2103, page 10	(D) = (A)+(B)+(C)
Series (Refunded Issue)	Issuance and Redemption	Investment Income Differential	Discount	Total
1993	$ 44,604	$ 10,665	$ 33,651	$ 88,919
1995A	75,964	1,281	25,784	103,029
1996A	39,893	2,018	37,422	79,333
1996B	17,184	549	1,661	19,393
1997A	54,136	17,037	-	71,173
Refunding 1998A	54,247	-	-	54,247
(1982)	45,762	35,977	-	81,739
(1987)	116,739	1,200	-	117,939
Subtotal	216,748	37,177	-	253,925
Refunding 1999B	39,627	-	17,953	57,580
(1988)	17,243	-	-	17,243
(1988 Conv)	43,030	-	-	43,030
Subtotal	99,900	-	17,953	117,853
1999C	37,330	26,168	-	63,499
Refunding 1999D	20,830	-	-	20,830
(1990A)	29,573	(1,162)	-	28,411
Subtotal	50,403	(1,162)	-	49,241
Refunding 2000	59,427	-	5,847	65,274
(1990B)	36,597	(399)	-	36,198
(1990C)	51,386	27,660	-	79,046
Subtotal	147,410	27,261	5,847	180,518
2002A	52,946	43,618	9,476	106,040
Refunding 2003B	78,137	-	-	78,137
(1992)	70,239	46,261	-	116,500
Subtotal	148,376	46,261	-	194,637
Total	$ 984,895	$ 210,873	$ 131,794	$ 1,327,562

Please refer to HECO-WP-2103 page 3 for original schedule and notes.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Revenue Bonds
Schedule of Issuing Expenses (Includes Amortization Differential)

	(A)	(B)	(C)	(D)= (B)-(C)	(E)	(F) = (D)-(E)
Series (Refunded Issue)	2003 Annual Amortization	12/31/03 Unamortized Balance	2004 Annual Amortization	12/31/04 Unamortized Balance	2005 Annual Amortization	12/31/05 Unamortized Balance
1993	$ 44,604	$ 884,644	$ 44,604	$ 840,040	$ 44,604	$ 795,436
1995A *	55,214	605,423	55,214	576,592	75,964	921,261
1996A	39,893	890,949	39,893	851,056	39,893	811,163
1996B	17,184	166,130	17,184	148,946	17,184	131,762
1997A	54,136	479,453	54,136	425,317	54,136	371,181
Refunding 1998A	54,247	447,541	54,247	393,294	54,247	339,047
(1982)	45,762	377,537	45,762	331,775	45,762	286,013
(1987)	116,739	963,094	116,739	846,355	116,739	729,616
Subtotal	216,748	1,788,172	216,748	1,571,424	216,748	1,354,676
:funding 1999B	39,627	591,104	39,627	551,477	39,627	511,850
(1988)	17,243	899,076	17,243	838,803	17,243	778,530
(1988 Conv)	43,030	(incl.above)	43,030	(incl.above)	43,030	(incl.above)
Subtotal	99,900	1,490,180	99,900	1,390,280	99,900	1,290,380
1999C	37,330	964,370	37,330	927,040	37,330	889,709
Refunding 1999D	20,830	333,285	20,830	312,455	20,830	291,625
(1990A)	29,573	473,169	29,573	443,596	29,573	414,023
Subtotal	50,403	806,454	50,403	756,051	50,403	705,648
Refunding 2000	59,427	980,549	59,427	921,122	59,427	861,695
(1990B)	36,597	603,853	36,597	567,256	36,597	530,659
(1990C)	51,386	869,276	51,386	817,890	51,386	766,504
Subtotal	147,410	2,453,678	147,410	2,306,268	147,410	2,158,858
2002A	35,901	1,661,236	38,740	1,622,496	52,946	1,569,550
Refunding 2003B	49,856	1,478,091	78,137	1,399,954	78,137	1,321,817
(1992)	77,145	1,328,704	70,239	1,258,465	70,239	1,188,225
Subtotal	127,001	2,806,795	148,376	2,658,419	148,376	2,510,042
Total	$ 925,724	$ 14,997,484	$ 949,939	$ 14,073,928	$ 984,895	$ 13,509,666

Please refer to HECO-WP-2103 page 4 for original schedule and notes. Notes presented below represent
/ or revised information.

* Includes annual bond insurance premium accruals.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Revenue Bonds
Schedule of Issuance Costs

Series (Refunded Issue)	(A) 2003 Annual Amortization	(B) 12/31/03 Unamortized Balance	(C) 2004 Annual Amortization	(D) = (B)-(C) 12/31/04 Unamortized Balance	(E) 2005 Annual Amortization	(F) = (D)-(E) 12/31/05 Unamortized Balance
1993	$ 44,604	$ 884,644	$ 44,604	$ 840,040	$ 44,604	$ 795,436
1995A **	55,214	605,423	55,214	576,592	75,964	921,261
1996A	39,893	890,949	39,893	851,056	39,893	811,163
1996B	17,184	166,130	17,184	148,946	17,184	131,762
1997A	54,136	479,453	54,136	425,317	54,136	371,181
Refunding 1998A	54,247	447,541	54,247	393,294	54,247	339,047
(1982)	45,762	377,537	45,762	331,775	45,762	286,013
(1987)	116,739	963,094	116,739	846,355	116,739	729,616
Refunding 1999B	39,627	591,104	39,627	551,477	39,627	511,850
(1988)	16,915	894,181	16,915	834,236	16,915	774,291
(1988 Conv)	43,030	(incl.above)	43,030	(incl.above)	43,030	(incl.above)
1999C	37,330	964,370	37,330	927,040	37,330	889,709
Refunding 1999D	20,830	333,285	20,830	312,455	20,830	291,625
(1990A)	29,573	473,169	29,573	443,596	29,573	414,023
Refunding 2000	59,427	980,549	59,427	921,122	59,427	861,695
(1990B)	36,552	603,112	36,552	566,560	36,552	530,008
(1990C)	50,197	849,158	50,197	798,961	50,197	748,764
2002A	35,901	1,661,236	38,740	1,622,496	52,946	1,569,550
Refunding 2003B	49,856	1,478,091	78,137	1,399,954	78,137	1,321,817
(1992)	76,642	1,319,181	69,736	1,249,445	69,736	1,179,708
Total	$ 923,659	$ 14,962,207	$ 947,874	$ 14,040,716	$ 982,830	$ 13,478,519

Please refer to HECO-WP-2103 page 4 for original schedule and notes. Notes presented below represent new or revised information.

** Series 1995A includes annual bond insurance premium payment accrual of $26,383, calculated as follows:

Total Series 1995A Issue	$ 47,000,000
6.5 Basis Points of Par Outstanding Annually (per MBIA Insurance Policy)	0.065%
Annual insurance premium (rounded)	$ 31,000
HECO portion = $40,000,000 / $47,000,000)	85.11%
HECO's annual insurance premium	$ 26,383

Also, the Series 1995A 2005 amortization includes amortization related to $400,000 redemption premium and $15,000 in redemption costs (estimated), as calculated below:

Redemption premium (Bond redeemed on January 1, 2005)	$ 400,000
Attorney/Trustee costs	15,000
Total redemption costs	$ 415,000
Years to original maturity (Year 2025 per bond documents)	20
Annual amortization	$ 20,750
Unamortized redemption costs inlcuded in 12/31/05 balance	$ 394,250

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Embedded Cost of Long-Term Debt
Test Year 2005 Average
($ Thousands)

	(A)	(B)	(C) = (A)*(B)	(D) = WP-2103, p.3	(E) = (C)+(D)
Long-Term Debt	Rate	Net Proceeds	Annual Interest	Annual Amortization	Annual Requirement
Special Purpose Revenue Bonds (Refunded Issue):					
Series 1993 ***	5.45%	$ 25,000	$ 1,363	$ 90	$ 1,452
Series 1995A ***	6.60%	20,000	1,320	103	1,423
Series 1996A	6.20%	48,000	2,976	79	3,055
Series 1996B	5 7/8%	14,000	823	19	842
Series 1997A	5.65%	50,000	2,825	71	2,896
Refunding Series 1998A (1987)	4.95%	42,580	2,108	254	2,362
Refunding Series 1999B (1988)	5.75%	30,000	1,725	118	1,843
Series 1999C	6.20%	35,000	2,170	63	2,233
Refunding Series 1999D (1990A)	6.15%	16,000	984	49	1,033
Refunding Series 2000 (1990B&C)	5.70%	46,000	2,622	181	2,803
Series 2002A ***	5.10%	33,644	1,716	106	1,822
Refunding Series 2003B (1992)	5.00%	40,000	2,000	195	2,195
Unamortized Costs, Revenue Bonds *		(20,377)			
Unamortized Costs, First Mtg Bonds		(770)			

Hawaiian Electric Company, Inc.

Series 1993, 1995A, and 2002A Special Purpose Revenue Bonds

			(A)	(B)	(C) = (A)+(B)
	Series 1993	Series 1995A	Series 2002A	Construction Fund	Series 2002A, Net
Outstanding as of December 31, 2003	$ 50,000,000	$ 40,000,000	$ 40,000,000	$ (14,013,000)	$ 25,987,000
2004 Activity	-	-	-	1,301,800 **	1,301,800
Outstanding as of December 31, 2004	50,000,000	40,000,000	40,000,000	(12,711,200)	27,288,800
2005 Activity	(50,000,000) *	(40,000,000) *	-	12,711,200 **	12,711,200
Outstanding as of December 31, 2005	$ -	$ -	$ 40,000,000	$ -	$ 40,000,000
Test Year 2005 Average = [(2004)+(2005)]/2	**$ 25,000,000**	**$ 20,000,000**			**$ 33,644,400**

* Per bond documents, HECO can early redeem the Series 1993 bonds without having to pay any redemption premium while the Series 1995A bonds can be redeemed beginning January 1, 2005 at a 101% redemption price.

** Represents estimated drawdowns from the Series 2002A Construction Fund. Refer to WP-2103, p.12 for monthly drawdown information.

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Revenue Bonds
Summary of Unamortized Balances

Unamortized Costs	WP Reference	(A) 12/31/03 Unamortized Balance	(B) 12/31/04 Unamortized Balance	(C) 12/31/05 Unamortized Balance
Issuance and Redemption	DOD-IR-3-54 p.20	$ 14,997,484	$ 14,073,928	$ 13,523,000
Investment Income Differential	WP-2103 p.8	3,775,594	4,082,968	3,976,771
Issuance Discount	WP-2103 p.10	2,744,287	2,615,035	2,483,242
Total		$ 21,517,365	$ 20,771,932	$ 19,983,013
Test Year 2005 Average = [Total(B)+Total(C)]/2				**$ 20,377,473**

Please refer to HECO-WP-2103 page 2 for original schedule and notes

Totals may not add due to rounding

Hawaiian Electric Company, Inc.

Revenue Bonds
Summary of 2005 Annual Amortizations

	(A) = DOD-IR-3-54, p. 20	(B) = HECO-WP-2103, p.8	(C) = HECO-WP-2103, p.10	(D) = (A)+(B)+(C)
Series (Refunded Issue)	Issuance and Redemption	Investment Income Differential	Discount	Total
1993	$ 45,437	$ 10,665	$ 33,651	$ 89,752
1995A	75,964	1,281	25,784	103,029
1996A	39,893	2,018	37,422	79,333
1996B	17,184	549	1,661	19,393
1997A	54,136	17,037	-	71,173
Refunding 1998A	54,247	-	-	54,247
(1982)	45,762	35,977	-	81,739
(1987)	116,739	1,200	-	117,939
Subtotal	216,748	37,177	-	253,925
Refunding 1999B	39,627	-	17,953	57,580
(1988)	17,243	-	-	17,243
(1988 Conv)	43,030	-	-	43,030
Subtotal	99,900	-	17,953	117,853
1999C	37,330	26,168	-	63,498
Refunding 1999D	20,830	-	-	20,830
(1990A)	29,573	(1,162)	-	28,411
Subtotal	50,403	(1,162)	-	49,241
Refunding 2000	59,427	-	5,847	65,274
(1990B)	36,597	(399)	-	36,198
(1990C)	51,386	27,660	-	79,046
Subtotal	147,410	27,261	5,847	180,518
2002A	52,946	43,618	9,476	106,040
Refunding 2003B	78,137	-	-	78,137
(1992)	70,239	46,261	-	116,500
Subtotal	148,376	46,261	-	194,637
Total	$ 985,728	$ 210,873	$ 131,794	$ 1,328,395

Please refer to HECO-WP-2103 page 3 for original schedule and notes

Totals may not add exactly due to rounding.

Hawaiian Electric Company, Inc.

Revenue Bonds
Schedule of Issuing Expenses (Includes Amortization Differential)

	(A)	(B)	(C)	(D)= (B)-(C)	(E)	(F) = (D)-(E)
	2003	12/31/03	2004	12/31/04	2005	12/31/05
Series (Refunded Issue)	Annual Amortization	Unamortized Balance	Annual Amortization	Unamortized Balance	Annual Amortization	Unamortized Balance
1993	$ 44,604	$ 884,644	$ 44,604	$ 840,040	$ 45,437	$ 808,769
1995A *	55,214	605,423	55,214	576,592	75,964	921,261
1996A	39,893	890,949	39,893	851,056	39,893	811,163
1996B	17,184	166,130	17,184	148,946	17,184	131,762
1997A	54,136	479,453	54,136	425,317	54,136	371,181
Refunding 1998A	54,247	447,541	54,247	393,294	54,247	339,047
(1982)	45,762	377,537	45,762	331,775	45,762	286,013
(1987)	116,739	963,094	116,739	846,355	116,739	729,616
Subtotal	216,748	1,788,172	216,748	1,571,424	216,748	1,354,676

Hawaiian Electric Company, Inc.

Revenue Bonds
Schedule of Issuance Costs

Series (Refunded Issue)	(A) 2003 Annual Amortization	(B) 12/31/03 Unamortized Balance	(C) 2004 Annual Amortization	(D) = (B)-(C) 12/31/04 Unamortized Balance	(E) 2005 Annual Amortization	(F) = (D)-(E) 12/31/05 Unamortized Balance
1993 **	$ 44,604	$ 884,644	$ 44,604	$ 840,040	$ 45,437	$ 808,769
1995A **	55,214	605,423	55,214	576,592	75,964	921,261
1996A	39,893	890,949	39,893	851,056	39,893	811,163
1996B	17,184	166,130	17,184	148,946	17,184	131,762
1997A	54,136	479,453	54,136	425,317	54,136	371,181
Refunding 1998A	54,247	447,541	54,247	393,294	54,247	339,047
(1982)	45,762	377,537	45,762	331,775	45,762	286,013
(1987)	116,739	963,094	116,739	846,355	116,739	729,616
Refunding 1999B	39,627	591,104	39,627	551,477	39,627	511,850
(1988)	16,915	894,181	16,915	834,236	16,915	774,291
(1988 Conv)	43,030	(incl.above)	43,030	(incl.above)	43,030	(incl.above)
1999C	37,330	964,370	37,330	927,040	37,330	889,710
Refunding 1999D	20,830	333,285	20,830	312,455	20,830	291,625
(1990A)	29,573	473,169	29,573	443,596	29,573	414,023
Refunding 2000	59,427	980,549	59,427	921,122	59,427	861,695
(1990B)	36,552	603,112	36,552	566,560	36,552	530,008
(1990C)	50,197	849,158	50,197	798,961	50,197	748,764
2002A *	35,901	1,661,236	38,740	1,622,496	52,946	1,569,550
Refunding 2003B	49,856	1,478,091	78,137	1,399,954	78,137	1,321,817
(1992)	76,642	1,319,181	69,736	1,249,445	69,736	1,179,708
Total	$ 923,659	$ 14,962,207	$ 947,873	$ 14,040,716	$ 983,663	$ 13,491,853

Please refer to HECO-WP-2103, page 4 for original schedule and notes.

[redacted]

** Series 1995A includes annual bond insurance premium payment accrual of $26,383, calculated as follows:

DOD/HECO-IR-3-55

[Gnechten Direct, p. 25, HECO-2116]

a. Provide S&P's definition of "funds from operations," and "total debt."

b. Please provide all of the calculations and assumptions used to produce the financial guidelines for "no rate increase" and "with rate increase" cases. Please provide these data in spreadsheet format with all formulas and supporting schedules available and unlocked. If any adjustment's have been made to per books numbers, please detail and describe any such adjustments.

HECO Response:

a. Per Standard & Poor's Ratings and Ratios information (see attached on page 2 to this response):

"Funds from operations" = Net income from continuing operations plus depreciation, amortization, deferred income taxes, and other noncash items

"Total debt" = Long-term debt (including amount for operating lease debt equivalent) plus current maturities, commercial paper, and other short-term borrowings

b. See attached spreadsheets for the financial ratio calculations for the "no rate increase" on pages 3 to 7 and "with rate increase" cases on pages 8 to 12 to this response. The financial ratio calculations reflected in HECO-WP-2116, pages 1 to 10 were revised for additional notations.

FORMULAS FOR KEY RATIOS

1. EBIT interest coverage = $\dfrac{\text{Earnings from continuing operations* before interest and taxes}}{\text{Gross interest incurred before subtracting (1) capitalized interest and (2) interest income}}$

2. EBITDA interest coverage = $\dfrac{\text{Earnings from continuing operations* before interest, taxes, depreciation, and amortization}}{\text{Gross interest incurred before subtracting (1) capitalized interest and (2) interest income}}$

$\dfrac{\text{amortization, deferred income taxes, and other noncash items}}{\text{Long-term debt** plus current maturities, commercial paper, and other short-term borrowings}}$

4. Free operating cash flow/total debt = $\dfrac{\text{Funds from operations minus capital expenditures, minus (plus) the increase (decrease) in working capital (excluding changes in cash, marketable securities, and short-term debt)}}{\text{Long-term debt** plus current maturities, commercial paper, and other short-term borrowings}}$

5. Return on capital = $\dfrac{\text{EBIT}}{\text{Average of beginning of year and end of year capital, including short-term debt, current maturities, long-term debt**, non-current deferred taxes, and equity.}}$

6. Operating income/sales = $\dfrac{\text{Sales minus cost of goods manufactured (before depreciation and amortization), selling, general and administrative, and research and development costs}}{\text{Sales}}$

7. Long-term debt/capital = Long-term debt**

HECO-WP-2116 (revised)
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Hawaiian Electric Company, Inc.
Test Year 2005

Income Statement
NO Rate Increase & WITH Debt Equivalent

	$ in thousands	HECO Reference
Operating Income	44,625	2301

[redacted]

	$ in thousands	HECO Reference
Revised Operating Income	50,000	
AFUDC	8,010	2107
Annual Debt Requirement:		
Short-term Debt ($39,929 x 3.5%)	1,398	2102
Long-term Debt	26,723	2103
Hybrid	2,061	2104
Total Annual Debt Requirement	30,182	

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations Interest Coverage
NO Rate Increase & WITH Debt Equivalent

	$ in thousands		HECO Reference
Revised Operating Income	50,000		WP-2116, p. 1
Depreciation & Amortization	72,056		2301
Deferred Income Taxes	(1,292)		1705
State Capital Goods Excise Credit ($16,356 - $15,167)	1,189		1704
Interest on Debt Equivalent [1]	23,944		WP-2116, p. 11
Total	145,897	A	
Total Debt Requirement (ST, LT & Hybrids)	30,182		WP-2116, p. 1
Interest on Debt Equivalent	23,944		WP-2116, p. 11
	54,126	B	
Fund from Operations Interest Coverage (A)/(B)	2.70	x	

[1] Interest on Debt Equivalent is not reflected in the book numbers. Interest on Debt Equivalent represents the interest expense that the Company would have incurred if the debt equivalent was reflected as a debt obligation on the Company's balance sheet.

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations / Average Total Debt
NO Rate Increase & WITH Debt Equivalent

	$ in thousands		HECO Reference
Revised Operating Income	50,000		WP-2116, p. 1
Depreciation & Amortization	72,056		2301
Deferred Income Taxes	(1,292)		1705
State Capital Goods Excise Credit	1,189		1704
Interest Expense:			
Short-term interest ($39,929 x 3.5%)	(1,398)		2102
Long-term interest	(25,313)		2103
Hybrid interest	(2,051)		2104
Total Interest Expense	(28,762)		
Total	93,191	A	
Average Debt:			
Short-term Debt	39,929		2102
Long-term Debt [1]	445,225		2103
Hybrid [1]	30,000		2104
Debt Equivalent (30%) [2]	243,404		WP-2116, p. 11
Average Total Debt	758,558	B	
FFO to Ave Total Debt Ratio (A)/(B)	0.12		

[1] Excludes unamortized costs.

[2] Debt Equivalent is not reflected in the book numbers. Represents the imputed debt of the Company's Purchase Power contracts.

Hawaiian Electric Company, Inc.
Test Year 2005

Total Debt / Total Capital
NO Rate Increase & WITH Debt Equivalent

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Current Total Debt:			
Short-term Debt	32,072		2102
Long-term Debt [1]	451,581		2103; WP-2103, p.1
Hybrid Securities [2]	30,000		2104
Current Total Debt	513,653		
Debt Equivalent (30%) [3]	239,438		WP-2116, p. 11
Revised Total Debt	753,091	A	
Preferred Stock [2]	22,293		2105
Common Stock	639,906		2106
Total Capital	1,415,290	B	
Total Debt / Total Capital Ratio (A)/(B)	0.53		

[1] Excludes unamortized costs and assumes Series 2002A to be fully drawn by 12/31/05.

[2] Excludes unamortized costs.

[3] Debt Equivalent is not reflected in the book numbers. Represents the imputed debt of the Company's Purchase Power contracts.

Hawaiian Electric Company, Inc.
Test Year 2005

Total Debt / Total Capital
NO Rate Increase & WITHOUT Debt Equivalent

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Current Total Debt:			
Short-term Debt	32,072		2102
Long-term Debt [1]	451,581		2103; WP-2103, p.1
Hybrid Securities [2]	30,000		2104
Current Total Debt	513,653		
Debt Equivalent (30%)	0		
Revised Total Debt	513,653	A	
Preferred Stock [2]	22,293		2105
Common Stock	639,906		2106
Total Capital	1,175,852	B	
Total Debt / Total Capital Ratio (A)/(B)	0.44		

[1] Excludes unamortized costs and assumes Series 2002A to be fully drawn by 12/31/05.

[2] Excludes unamortized costs.

Hawaiian Electric Company, Inc.
Test Year 2005

Income Statement
WITH Rate Increase & WITH Debt Equivalent
Based on a 11.5% Earned Return on Common Equity

	$ in thousands	HECO Reference
Operating Income	99,453	2301
Adj related to DSM Utility Incentive	5,375	Note A
Revised Operating Income	104,828	
AFUDC	8,010	2107
Annual Debt Requirement:		
Short-term Debt ($39,929 x 3.5%)	1,398	2102
Long-term Debt	26,723	2103
Hybrid	2,061	2104
Total Annual Debt Requirement	30,182	
Net Income	82,656	
Annual requirement on Preferred Stock	1,135	2105
Net Income for Common	81,521	

Note A:

DSM Utility Incentives	8,799	HECO-1019
Income Tax Impact (38.91%)	(3,424)	
Adjustment for DSM Utility Incentives	5,375	

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations Interest Coverage
WITH Rate Increase & WITH Debt Equivalent
Based on a 11.5% Earned Return on Common Equity

	$ in thousands		HECO Reference
Revised Operating Income	104,828		WP-2116, p. 6
Depreciationn & Amortization	72,056		2301
Deferred Income Taxes	(1,292)		1705
State Capital Goods Excise Credit ($16,356 - $15,167)	1,189		1704
Interest on Debt Equivalent [1]	23,944		WP-2116, p. 11
Total	200,725	A	
Total Debt Requirement (ST, LT & Hybrids)	30,182		WP-2116, p. 6
Interest on Debt Equivalent	23,944		WP-2116, p. 11
	54,126	B	
Fund from Operations Interest Coverage (A)/(B)	3.71	x	

[1] Interest on Debt Equivalent is not reflected in the book numbers. Interest on Debt Equivalent represents the interest expense that the Company would have incurred if the debt equivalent was reflected as a debt obligation on the Company's balance sheet.

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations / Average Total Debt
WITH Rate Increase & WITH Debt Equivalent
Based on a 11.5% Earned Return on Common Equity

	$ in thousands		HECO Reference
Revised Operating Income	104,828		WP-2116, p. 6
Depreciation & Amortization	72,056		2301
Deferred Income Taxes	(1,292)		1705
State Capital Goods Excise Credit	1,189		1704
Interest Expense:			
Short-term interest ($39,929 x 3.5%)	(1,398)		2102
Long-term interest	(25,313)		2103
Hybrid interest	(2,051)		2104
Total Interest Expense	(28,762)		
Total	148,019	A	
Average Debt:			
Short-term Debt	39,929		2102
Long-term Debt [1]	445,225		2103
Hybrid [1]	30,000		2104
Debt Equivalent (30%) [2]	243,404		WP-2116, p. 11
Average Total Debt	758,558	B	
FFO to Ave Total Debt Ratio (A)/(B)	0.20		

[1] Excludes unamortized costs.

[2] Debt Equivalent is not reflected in the book numbers. Represents the imputed debt of the Company's Purchase Power contracts.

Hawaiian Electric Company, Inc.
Test Year 2005

Total Debt / Total Capital
WITH Rate Increase & WITH Debt Equivalent
Based on a 11.5% Earned Return on Common Equity

	$ in thousands	HECO Reference
Capitalization Balances at Year-End:		
Current Total Debt:		
Short-term Debt	32,072	2102
Long-term Debt [1]	451,581	2103; WP-2103, p.1
Hybrid Securities [2]	30,000	2104
Current Total Debt	513,653	
Debt Equivalent (30%) [3]	239,438	WP-2116, p. 11
Revised Total Debt	753,091 A	
Preferred Stock [2]	22,293	2105
Common Stock	639,906	2106
Total Capital	1,415,290 B	
Total Debt / Total Capital Ratio (A)/(B)	$\boxed{0.53}$	

[1] Excludes unamortized costs and assumes Series 2002A to be fully drawn by 12/31/05.

[2] Excludes unamortized costs.

[3] Debt Equivalent is not reflected in the book numbers. Represents the imputed debt of the

Hawaiian Electric Company, Inc.
Test Year 2005

Total Debt / Total Capital
WITH Rate Increase & WITHOUT Debt Equivalent
Based on a 11.5% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Current Total Debt:			
Short-term Debt	32,072		2102
Long-term Debt [1]	451,581		2103; WP-2103, p.1
Hybrid Securities [2]	30,000		2104
Current Total Debt	513,653		
Debt Equivalent (30%)	0		
Revised Total Debt	513,653	A	
Preferred Stock [2]	22,293		2105
Common Stock	639,906		2106
Total Capital	1,175,852	B	
Total Debt / Total Capital Ratio (A)/(B)	0.44		

[1] Excludes unamortized costs and assumes Series 2002A to be fully drawn by 12/31/05.

[2] Excludes unamortized costs.